FILED
03/01/22
08:52 AM
R2001007

R.20-01-007 TRACK 2 – GAS INFRASTRUCTURE

WORKSHOP REPORT
MARCH 1, 2022

California Public Utilities Commission

A digital copy of this report can be found at:
https://www.cpuc.ca.gov/gasplanningoir

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1 INTRODUCTION

On January 10, 2022, and January 24, 2022, the California Public Utility Commission's (CPUC or Commission) Energy Division hosted two workshops for Track 2 of Rulemaking (R.) 20-01-007, the Long-Term Gas Planning Rulemaking.[1] An Amended Scoping Ruling was issued January 5, 2022, containing the questions addressed in these workshops.[2] The purpose of the workshops was to provide stakeholders with a common understanding of the issues, gather information, and seek feedback.

2 BACKGROUND

California's ambitious decarbonization goals will require changes to the state's gas system. This rulemaking is designed to begin the process of charting a course through the transition years. During this period, the CPUC will need to balance competing interests and priorities as it helps move California toward an energy system, that is safe, reliable, affordable, equitable, and green.

The Long-Term Gas Planning Rulemaking was opened on January 20, 2020, and was divided into two tracks. Track 1 was further divided into Track 1a and Track 1b. Track 1a examined the natural gas reliability standards that were established in Decision (D.) 06-09-039 to determine whether they were still adequate and whether they were being met. Track 1b addressed market structure and pipeline operating procedures. A Proposed Decision in Track 1 is forthcoming.

Track 2 of this proceeding is designed to develop and implement a long-term gas planning strategy. It is divided into three sub-tracks: Track 2a, Gas Infrastructure; 2b, Equity, Rate Design, Gas Revenues, Safety, and Workforce Issues; and Track 2c, Data and Process. The Track 2a workshops described in this report broadly address how the Commission should determine the appropriate gas infrastructure portfolio for gas utilities that operate in California. The natural gas infrastructure discussed in this report includes transmission, distribution, and service pipelines; the regulating and compression equipment that helps move gas through them; and gas storage facilities. While the focus of this report is on gas infrastructure, it is important to note that the state's gas and electric systems are currently interdependent. Decisions made for gas infrastructure have the potential to impact electric rates and reliability.

3 TRACK 2 WORKSHOPS

Both the January 10, 2022, and January 24, 2022, workshops were held remotely, due to Covid-19 pandemic limitations on in-person gatherings. Staff sent notice of the workshop to the service list of the rulemaking and several other related service lists. The public workshop notice was posted on the CPUC's Daily Calendar and website.

The workshops included morning and afternoon sessions, as seen in the agendas in Appendices A and B. In sections 4 and 5 below, the workshop summaries are organized in order of the agenda panels, which generally reflect the order of the Amended Scoping Document.

[1] The Amended Scoping Memo can be found at [436692151.PDF (ca.gov)](436692151.PDF (ca.gov)).

[2] Amended Scoping Memo Questions 2.1.1 through k, pgs. 4-7.

4 WORKSHOP 1 GAS INFRASTRUCTURE

4.1 Panel 1: Site-Specific Approval for Gas Infrastructure

Scoping Memo Question a: Should the Commission consider adopting a General Order (GO) analogous to GO 131-D for electric infrastructure projects, that would require site-specific approvals for gas infrastructure projects that exceed a certain size or cost?[3]

4.1.1 CPUC Energy and Legal Divisions

Mary Jo Borak, head of Energy Division's California Environmental Quality Act (CEQA) section and Jack Mulligan of Legal Division presented jointly. They noted that GO 131-D—which contains rules relating to the planning and construction of California's electric generation, transmission, and distribution line facilities and substations—was last modified in 1995. Among the goals for the revisions were to provide public notice of proposed electrical projects above a certain size, to allow an opportunity for affected parties to be heard by the Commission, and to create a streamlined mechanism for handling complaints.

GO 131-D requires that utilities receive one of two types of authorization from the Commission before beginning construction on certain electric projects. For electric transmission lines above 200 kilovolts (kV), the Commission must find that they are necessary to promote the safety, health, comfort, and convenience of the public before issuing a Certificate of Public Convenience and Necessity (CPCN). For electric transmission lines between 50kV and 200 kV and electric substations with a capacity above 50 kV, the Commission must issue a Permit to Construct (PTC).

Exemptions to GO 131-D include: 1) power facilities with in-service dates before January 1, 1996; 2) replacement of existing power line facilities with equivalent facilities; 3) minor relocation of power lines up to 2,000 feet in length; 4) conversion of power lines from overhead to underground; 5) facilities that have undergone environmental review by another agency; 6) power line facilities located in existing franchise or other designated corridor; and 7) construction of projects that are statutorily exempt pursuant to Section 15200 et seq. of the CEQA Guidelines.

There are cases in which exceptions to these exemptions in GO 131-D are allowed, which include: 1) if there is a reasonable possibility the activity could impact an environmental resource of hazardous or critical concern; 2) the cumulative impact of successive projects of the same type in the same place over time is significant; and 3) there is a reasonable possibility the activity will have a significant effect on the environment due to unusual circumstances.

4.1.2 PG&E

Jenny Everett, the Principal Land Planner for PG&E, noted that in addition to what was described in the previous presentation, GO 131-D also created a notice and exemption system that provides system planners with certainty that most projects can be developed quickly with little risk of regulatory delay. Ms. Everett added that the GO provides clarity that local discretionary review of utility projects is prohibited.

The process begins with a review of the electric grid by the California Independent System Operator (CAISO) to identify system upgrades that are needed. The utility then begins reviewing the proposed project, preparing a design and studying the permitting requirements, which may include permits from other entities beyond the CPUC. If permits are triggered, the utility must file an application with the permitting

[3] GO 131-D, "Planning and Construction of Facilities for the Generation of Electricity and Certain Electric Transmission Facilities" can be found at https://www.cpuc.ca.gov/proceedings-and-rulemaking/cpuc-general-orders.

agencies for discretionary action. Where permits are required, GO 131-D provides a process for environmental review as warranted under CEQA and also demonstrates to local government that the CPUC has discretionary authority over all utility electric projects, regardless of whether GO 131-D requires a Commission permit.

GO 131-D is not a system planning process, nor a ratemaking process. While project need is considered in CPCN proceedings, it consists mostly of validating previous system planning decisions. PTC proceedings do not consider project need. Similarly, project cost is beyond the scope of PTC proceedings and CPCN proceedings provide for only limited and nonbinding considerations of cost.

PG&E has applied for multiple CPNCs and PTCs. It has also filed hundreds of notice of construction (NOC) and advice letter filings exempt from CPUC permit requirements and held many informal consultations with local governments. In addition, PG&E is required to obtain and comply with all required federal and state permits.

Ms. Everett stated that GO 131-D has provided a forum for resolving multi-stakeholder disputes related to aesthetics, electro-magnetic fields, and other local land use concerns – particularly on large projects passing through multiple jurisdictions where various competing interests must be weighed. Generally, it provides system planners with certainty through expedited approval or exemptions where appropriate based on environmental benefits and puts to rest local government claims of discretionary authority over utility electric projects. However, Ms. Everett noted that where permits are required, the process can be costly and time-consuming. The requirements have increased and now require surveys for all alternatives including rebuild projects of existing facilities. In some cases, there is a duplication of prior planning processes. Costs for mitigation of significant environmental impacts have steadily increased and represent a significant percentage of the overall cost of projects that require CPUC permits.

Ms. Everett presented the following table documenting time to approval for various specific projects, spanning from the shortest of one year, one month (for Embarcadero-Potrero) to the longest of over five years for the still unresolved Estrella project.

Table 1: PG&E Table of CPCN and PTC Approval Times

Sample Time to approval: CPCNs & PTCs

Project	CPCN / PTC	Application Date	Approval Date	Timeline for CPUC approval
Windsor Substation	PTC	April 2010	April 2014	4 years
Embarcadero- Potrero	CPCN	December 2012	January 2014	1 year & 1 month
Cressy-Gallo 115 kV Power Line	PTC	November 2011	January 2014	2 years & 3 months
Missouri Flat-Gold Hill 115 kV	PTC	August 2013	October 2015	2 years & 2 months
Sanger Substation	PTC	May 2015	July 2017	2 year & 2 months
South of Palermo 115kV	PTC	April 2016	June 2018	2 years & 2 months
Fulton-Fitch Mountain 60 kV	PTC	December 2015	December 2017	2 years
Estrella	PTC	January 2017	On going	Still in Progress, + 5 years
Ravenswood- Cooley Landing	PTC	December 2017	March 2019	1 year & 3 months
Martin Bus	CPCN	December 2017	June 2020	2 Years & 6 months
Vierra 115kV	PTC	June 2018	June 2021	3 years
Humboldt Bay- Humboldt #1 60kV	PTC	February 2019	November 2020	1 Year & 9 months

- PG&E typically spends over a year preparing the Proponents Environmental Assessment (PEA) which includes surveys and environmental analysis prior to the Permit's Application date

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Ms. Everett described the Estrella project in some detail. It is a proposed 230/70kV substation and a new 70 kV power line to improve reliability in the San Luis Obispo area. The Proponent's Environmental Assessment was submitted in January 2017 and has received multiple requests for additional information. She estimated that current costs to respond are about $4.7 million. A final EIR is expected in spring 2022.

Ms. Everett stated that the notice of construction process has much shorter timelines to approval, ranging from an average of 41 days in 2021 to an average of 103 days in 2019.

Her presentation ended with a question, in response to Question a: "Is there a demonstrated need for additional environmental permitting requirements on top of the many that already exist?"

4.1.3 SoCalGas

Albert Garcia, the Director of Environmental Services for SoCalGas, provided a brief history of the goals of GO 131-D, which he characterized as reviewing the need for proposed projects, examining environmental impacts for projects that otherwise have no discretionary agency review triggering CEQA, and clarifying the CPUC's preemptory authority Mr. Garcia stated that the historical drivers for electric permitting are largely absent with gas infrastructure. This is because the need for projects is separately addressed through processes such as general rate cases and the planning process envisioned by this rulemaking.

Therefore, Mr. Gacia maintained that a GO for gas infrastructure is not necessary because existing environmental review is sufficient. Most non-routine projects already require regional or state discretionary approval that triggers CEQA review, and there is no need to create a new regime to deal with the rare exceptions since the CPUC retains jurisdiction to address complaints and concerns. Mr. Garcia also noted that a GO is not necessary for routine construction and operations and maintenance (O&M) work, which is exempt from CEQA for electric infrastructure. Further, non-routine gas projects are not being undertaken at the same rate as the electric infrastructure projects that were taking place at the time GO 131-D was revised. He added that the CPUC's preemptory authority is well established, and thus there is no administrative demand to address it categorically.

If the CPUC decides to develop a gas permitting GO, SoCalGas recommends the following exemptions: 1) projects that are part of a compliance or safety program; 2) gas infrastructure projects that require a discretionary permit and CEQA review by another agency; and 3) routine construction and operation and maintenance projects that are analogous to the electric projects that are exempted.

Permits could be required for projects that result in a specified increase of the system's receipt point and/or backbone transmission zone capacity or a specified increase in horsepower. However, project costs and needs should be not re-reviewed. Finally, any new GO should state that "that local jurisdictions acting pursuant to local authority are preempted from regulating" gas infrastructure projects.

4.1.4 Earthjustice

Matt Vespa, an attorney and consultant to Earthjustice, began his presentation with a discussion of SoCalGas' Ventura Compressor Station project, which was approved by the CPUC in Decision (D) 19-05-051 as part of a General Rate Case. He showed an aerial photo of the area surrounding the Compressor Station, noting the proximity of a local school, a Boys and Girls Club, and nearby residential areas.

Mr. Vespa maintained that the review of the Ventura Compressor Replacement Project in the SoCalGas GRC was cursory, inadequate, and excluded engagement from impacted communities. He asserted that an environmental review by the CPUC is necessary to evaluate the need for the project and alternatives. He included the following graphic, which depicts areas he marked as potential alternative sites.

Figure 1: Ventura Compressor Station and Suggested Alternative Sites

Mr. Vespa also attested that since the California Energy Commission projects declining statewide natural gas demand, the expansion of the Ventura Compressor Station from a combined horsepower of 3,300 hp to 7,600 hp is unneeded. He also presented a page from an Executive Summary of SoCalGas' Proponent's Environmental Assessment" (PEA) as part of their Application for CEQA review for replacement of a gas compressor station at Aliso Canyon Storage Field with an electrical compressor station and stated that the Ventura Compressor Station Expansion should be subject to similar review under CEQA.

Mr. Vespa displayed a letter from the CPUC asking SoCalGas to meaningfully engage with the public, to conduct a more detailed feasibility analysis of alternative sites and configurations and to stop work on the Ventura Compressor Station while that analysis is being completed.

Mr. Vespa maintained that the GRC process is conducted in too short a timeframe to evaluate and implement alternatives. He provided a list of proposals for the circumstances in which the CPUC should require a public process for project-specific review, including:

- large compressor station projects;
- distribution and transmission line investments above a certain cost threshold; and
- whenever it is needed to ensure public health, safety, and environmental justice or when requested by local government.

4.1.5 Summary of Q&A

Jason Zeller asked whether GO 131-D is used to authorize repairs of existing transmission or distribution lines when there is a natural disaster such as a forest fire or earthquake. Mr. Mulligan responded that emergency situations operate outside of GO 131-D, whose main construct is environmental review and CEQA. CEQA allows emergencies to be addressed without doing the planning that would otherwise be required as the goal is to restore services to the public that have been impacted by an emergency as soon as possible.

Mr. Mulligan also responded to points raised by the previous panelists. He stated that PG&E's Estrella Project, which Mis. Everett mentioned, is taking longer than normal because the CPUC is looking at using distributed energy resources to meet the identified need in lieu of the $100 million proposed distribution level substation. Addressing Mr. Vespa's comments about the Ventura Compressor Station, Mr. Mulligan stated that the CPUC is looking at whether there are feasible alternatives and what those costs would be. With regard to CEQA, he stated that it has historically done a poor job of addressing environmental justice issues, adding that the Commission has adopted a better environmental justice plan than what CEQA requires, which is being rolled out now.

Mr. Mulligan noted that CEQA focuses on the harms of breaking new ground. Even if it might be bad planning to keep a facility where it is considering who its neighbors are, from the CEQA perspective, keeping the facility in place might look like the environmentally preferred alternative because everywhere else involves breaking new ground and having biological and other impacts. The Commission is trying to incorporate many different perspectives in addition to the environmental impacts that are included in CEQA. In the case of the Ventura Compressor Station, the Commission is looking at different alternatives, but it is outside of the CEQA process.

Mr. Mulligan also responded to SoCalGas' discussion of preemption and having other resource agencies review utilities' proposed projects. He noted that other agencies often prefer that the CPUC take the lead permitting role because of their own workload issues. Mr. Mulligan said that Commission staff want to be responsible about state government workload issues, which is one of the problems that could be rectified with a gas General Order. He also expressed discomfort with the idea of the gas company deciding where to submit a site-specific permit. A General Order would allow the Commission to determine the kinds of projects the gas company submits to the CPUC rather than having the utility decide which agency to apply to first.

Marcel Hawiger of TURN asked for examples of the types of large gas projects that would be covered by a gas GO 131-D. Ms. Borak responded that this is yet to be determined. New and replacement pipelines should be considered. Compressor stations, regulator stations, and valve stations would likely be areas to include since they are similar to electric substations. Ms. Borak said that the CPUC does not normally do an environmental review of electric transmission line replacement projects, but gas replacement projects may need to be considered for review if a General Order is adopted because there are different policy concerns on the gas side. She referred to the replacement of Line 1600 as an example, stating that it created a lot of stranded asset implications. Managing the gas system and limiting stranded assets requires more review of costly replacements than they are currently getting. The CPUC needs to put public safety first. However, in that case, SoCalGas testified that Line 1600 could be de-rated to manage safety issues. She noted that that's the type of project that should be evaluated publicly. She further said that people can't weigh in in the absence of an environmental review process, which is problematic. If there is an environmental review process that engages stakeholders, more viewpoints can be brought in that would otherwise be missed.

Norm Pederson asked SoCalGas to respond to Mr. Vespa's presentation on the Ventura compressor project. Albert Garcia stated that SoCalGas is looking at alternatives—not just relocation, but other alternatives—such as whether electric or electric hybrid compressors will work well at that site. He argued that this shows that the existing permitting process functioned as intended. He noted that there is a complaint process, which is effective.

4.2 Panel 2: Criteria for Repairing or Replacing Transmission Lines

Scoping Memo Question b: What criteria should the Commission use to determine whether aging transmission infrastructure should be repaired or replaced when a gas utility requests ratepayer funds?

i. Should the repair or replacement criteria be based on whether that piece of infrastructure is necessary to meet the utility's design standard as determined in Track 1?
ii. What other criteria might be considered?
iii. How should the cost to repair or replace the infrastructure be balanced against its reliability benefits?

4.2.1 PG&E

Bryon Winget, PG&E's Director of Gas Investment Planning, stated that a utility's design standard should be among the criteria for determining whether a pipeline is repaired or replaced. He discussed the example of PG&E's proposed retirement of the Tionesta Compressor Station. While the retirement would reduce the Malin receipt point's capacity, PG&E would still be able to meet its system design standards, and it would save more than $80 million in capital costs. Mr. Winget also discussed PG&E's integrated scoping and electrification process, which he stated has led to targeted system reductions since 2019. These include the deactivation of high-pressure regulators, distribution regulation stations, and dozens of miles of transmission pipelines as well as miles of transmission pipelines being downrated to distribution.

Mr. Winget also suggested other criteria that might be considered when determining whether to repair or replace transmission, including safety, risk, reliability, compliance, obligation to serve, and relocation as required by others. Cost effective opportunities to deactivate pipelines or electrify customers are dependent on the following: 1) modification of obligation to serve; 2) customer feasibility or practicality; and 3) consideration of flexible accounting policies, i.e., expense vs. capital. Mr. Winget also stated that, where deactivation and electrification is not cost effective, there is a need for innovative external funding sources.

The cost to repair or replace the infrastructure should be balanced against its reliability benefits by answering the following questions: Is there is a continued need for the pipeline to meet customer or operational needs? Is an investment required to safely operate and maintain the system in order to meet state and federal requirements? Will the gas investment allow a utility to respond efficiently and cost effectively to active threats on its system? Mr. Winget noted that some redundancy is required to enable the utility to perform required safety work while maintaining reliability. As an example, he stated that three transmission pipelines serve San Francisco despite the fact that the city's load can be met with two transmission pipelines. However, since pipelines must be periodically taken out of service for required maintenance, the third transmission line is necessary to ensure reliability. Similarly, the utility maintains extra compressor stations to provide a backstop if one compressor station is out of service.

Mr. Winget finished his presentation by noting that low utilization, high maintenance cost facilities such as farm taps and gas gathering lines offer opportunities for decommissioning.

4.2.2 Environmental Defense Fund

Michael Colvin, Director of the Environmental Defense Fund's (EDF's) California Energy Program, maintained that the criteria for determining whether aging infrastructure should be replaced include the function the infrastructure is performing, the set of customers who will benefit from the project, and how long the asset will be used and useful. He stated that the Commission should plan for changes to the expected useful life of gas pipelines.

Mr. Colvin suggested several questions the Commission should ask before approving a new investment: 1) How does the new investment fit into the long-term plan? 2) What goal does the investment accomplish and why? 3) Can the same goal be accomplished in a different way? and 4) Who should pay for the investment? He noted that the cost of reliability is different for each customer category.

In determining whether a new investment is the only way to meet the energy obligation, the key is to focus on giving customers reliable energy, not necessarily reliable gas. Mr. Colvin suggested that the Commission should explore non-pipeline alternatives and noted that the Commission has a history of considering non-wires alternatives for electric infrastructure. When considering the appropriateness of a new investment, the Commission should weigh the inherent trade-off between affordability and reliability and determine whether the investment would help the utility meet its long-term vision to reach a carbon reduction goal.

Mr. Colvin suggested that a gas investment priority order be established. This should include non-pipeline alternatives such as gas energy efficiency, targeted electrification, and demand response programs. Leak repairs should also be prioritized to mitigate climate harm. Further, gas trading reforms, the use of advanced metering infrastructure (AMI) data, and time-of-use rates should be leveraged to minimize gas demand.

The cost savings from non-pipeline alternatives, which can be significant, should be shared between ratepayers and shareholders. Mr. Colvin also stated that the different expected useful lives of pipeline vs. non-pipeline alternatives should be considered when determining the costs and benefits to ratepayers.

4.2.3 Southern California Generation Coalition

Catherine Yap, a consultant with the Southern California Generation Coalition (SCGC), began by providing some context regarding the factors impacting pipeline safety. She noted that a 2012 INGAA Foundation study[4] concluded that age is not necessarily the most important factor affecting the safety of a pipeline, adding that pipelines should not be replaced just because they are older. Federal assessment guidelines address both time-variant and non-time-variant factors, and utilities are required to make any necessary repairs. Ms. Yap maintained that lines should be repaired rather than replaced wherever it is cost effective and sufficient to meet safety standards while acknowledging that it may be appropriate to replace sections of pipelines. In general, Ms. Yap advocated for a rational process that considers the most cost-effective means to ensure pipeline safety and reliable operations.

In response to Question 2.b.i, Ms. Yap stressed that each pipeline should be determined to be functionally necessary because the cost of owning and maintaining the pipeline is very significant. The need for the line should be periodically reevaluated to see whether it is still needed to meet the various utility design standards. However, she noted that it may be less likely that transmission lines can be taken out of service because they serve many customers. The determination as to whether a line should be repaired or replaced should be based on the most cost-effective means to ensure safe pipeline operations. Safe operations rely upon well maintained pipelines, which in turn provide reliable service.

Ms. Yap suggested that in situations where it is not clear if repairs would be sufficient, electric utility reliability or reliability for other services should be considered. For example, assuring gas service to generating plants located in an electric "load pocket" may be the only way to assure local electric reliability.

[4] The INGAA Foundation is "open to natural gas pipelines and companies that provide goods and services to natural gas pipelines." It sponsors "research aimed at promoting natural gas use and safe, efficient pipeline construction and operation." About (memberclicks.net)

In response to Quest 2.b.i.i.i regarding balancing the cost of infrastructure vs. its reliability benefits, Ms. Yap stated that gas utilities can curtail larger customers rather than build infrastructure to meet extreme weather-related demands. Reliability standards reflect this flexibility. The reliability standards combined with customer load levels and load locations drive the determination of which transmission lines must be operated. The utility is required by state and federal regulations to maintain a safe system. If the pipelines are operating, the utility must perform the requisite safety inspections and repairs. A utility should pursue the most cost-efficient approach to maintaining its system that meets both the safety and reliability standards imposed on it.

4.2.4 Cal Advocates

Mark Pocta, a Program Manager for the Commission's Public Advocates (Cal Advocates)[5] office, began by noting that his office is at the initial stages of considering these issues and how to address them. That said, he stated that the utilities' design standards should be an important factor in determining how much infrastructure to maintain.

While noting agreement with a lot of what others had said previously, Mr. Pocta added that it is important to consider operational considerations on the system. One example he provided was the SoCalGas Southern System minimum requirements, which are in addition to the utility design standard. He referred to PG&E removing some of their gas gathering facilities as an example of a situation where facilities could be removed from service based on unique system and customer characteristics. Contracting also impacts operations. Mr. Pocta pointed to the importance of having the inter- and intrastate transmission contracts held for core customers match up and be reasonably aligned with the utility design standards.

Mr. Pocta noted that the resiliency of the of the state system was an issue that hadn't yet been discussed. The state of California has access to a number of gas-producing regions, including gas basins in Canada, the Rocky Mountains, San Juan, and Permian, which is unique. He stated that it may be cost effective to retain and invest in transmission capacity to retain access to various interstate pipelines and producing regions because it allows for system flexibility, resiliency, and gas-on-gas competition. It may be prudent to retain access to multiple regions so that customers can access the region with the best prices and shift from basin to basin as prices vary seasonally or with changing conditions. So even though it might not seem optimal to retain all the transmission capacity, it might be worth doing to retain system flexibility.

With regard to question 2.b.i.i. on balancing costs and benefits, Mr. Pocta stated that the Commission will have to balance many different interests and perspectives when considering system flexibility and access to producing basins. While noting the difficulty of establishing a set of criteria now without knowing what the future holds with regard to accessing different regions of the country in different producing basins and in light of the expectation of decreases in natural gas demand on the system, Mr. Pocta and Cal Advocates look forward to collaborating with the other parties to help the state address these issues in the OIR.

4.2.5 Summary of Q&A

Marcel Hawiger of TURN asked Bryon Winget of PG&E to clarify what types of pipelines were decommissioned due to the customer electrification projects he described in his presentation. Mr. Winget responded by providing the following examples.

- In the Berkeley hills, the Brazil Room had erosion problems with its 1,300 feet of service line. Instead of replacing that line, PG&E provided the customer with cash incentives to convert the operation to propane. Mr. Winget noted that the customer didn't choose to go all-electric because they have a kitchen that they use for events.

[5] Mark Pocta's presentation did not include any slides.

- North of Winters, PG&E incentivized four customers who were served by a four-mile-long transmission line to go all electric, which will eliminate that stretch of pipeline.
- In Davenport, PG&E serves 80 customers at the end of 10 miles of transmission line that requires Transmission Integrity Management Plan (TIMP) work. PG&E is working with the entire community to reduce gas consumption so that the company can derate the line to distribution. It wasn't possible to go all electric because of a local glass blowing plant that needs natural gas. Mr. Winget stated that PG&E is very close to being able to reduce the pressure to distribution levels and thus avoid the expense of TIMP work. He noted that in addition to saving ratepayers money in future GRCs, reducing the pressure increases the safety of the line. Lower pressure lines are safer, and any leaks are much easier and more cost effective to manage.

Following up on PG&E's concern about financing and the question of which expenditures are treated as expense versus capital, Commissioner Rechtschaffen asked panelists whether this is just a matter of a set of accounting issues or whether it is related to utilities' natural preference for capital spending because it earns them a rate of return.

Mr. Pocta stated that while utilities are incentivized to make capital investments, he wasn't familiar enough with all the issues around electrification vs. gas to have a clear response. It would likely depend on each unique situation and what the tradeoffs are.

Michael Colvin of EDF responded that it's more than just a question of how the money is booked. If the investment is in physical plant, then it is recovered over the expected useful life of the project, whereas non-pipeline alternatives are generally going to involve an incentive. If that incentive is paid by ratepayers, it would be classified as an expense that is recovered under a much shorter time frame. Mr. Colvin also suggested that stakeholders consider who would be paying for the project over what period of time as well as which customers are getting the incentives vs. which customers are paying the incentives. If wealthier customers leave the system first, projects that might initially have seemed cost-effective become harder to pay for over time. It's not a straight accounting issue.

Norman Pederson of SCGC asked Matt Vespa of Earthjustice a question about the previous panel. He noted that two utilities made the point that GO 131-D was aimed at assuring clarity about the preemption issue and preempting local jurisdictions. He asked whether, in Mr. Vespa's view, the purpose of having CEQA review is not to preempt local jurisdiction but to ensure that the public has a say in gas projects.

Mr. Vespa responded that local governments are already preempted and the CPUC has jurisdiction. He stated that this argues for the creation of a process at the CPUC that gives the local government as well as community groups an avenue to express their concerns, to weigh the proposal, and to provide alternatives as would happen in a regular environmental review process, which is not currently available.

Commissioner Shiroma noted that there are a number of proceedings focused on safety and other issues, adding that the challenge for the CPUC will be to create a strategic plan for meeting the Senate Bill 100 goals while also providing for equity, safety, workforce development, etc. Commissioner Shiroma suggested that the CPUC may want to hold an infrastructure en banc.

Commissioner Rechtschaffen followed up by asking staff to comment on how the Commission keeps track of all the safety investments that are happening through programs such as the Pipeline Safety Enhancement Plan (PSEP). Jean Spencer, supervisor of Energy Division's Gas Policy and Reliability section, stated that PG&E is mostly finished with PSEP work while SoCalGas has a significant amount of work ongoing. Within Energy Division, the Gas Costs and Rates team works on PSEP, and they get regular updates on what projects have been completed and where the utilities are in the process. She noted that PSEP work is mandated by the Commission.

Ms. Spencer noted that the pipeline system as a whole is vast, and requests for funding come to the Commission piecemeal. She added that her section is working on a data request to get a better sense of what exactly is out there. It's a daunting task because the pipeline system is so extensive. Different segments of pipe have been worked on at different times, are made of different materials, and are situated in places with different soil and environmental conditions.

Commissioner Rechtschaffen agreed that it was a challenge, adding that the Commission now needs to look at all gas projects—from the Ventura Compressor Station to routine repair and replacement projects to safety projects—in the larger context of what else is going on and the other goals the Commission is trying to achieve. He underscored the need for the CPUC to put in place systematic approaches for evaluating gas projects. The Commissioner also stated that he would like to see the utilities doing a lot more of their own proactive evaluation of their systems such as the PG&E projects that Bryon Winget described, asking questions such as: Do we need to maintain these assets? Can we have a non-pipes alternative? What's the solution we can use going forward? He also noted that, later in this proceeding, the Commission would consider requiring the utilities to come up with proactive 10-year decarbonization plans so that they are affirmatively doing what our electric utilities are doing in the Integrated Resource Plan (IRP) process to move toward decarbonization.

Michael Colvin also responded to Commissioner Shiroma's question, stating that stakeholders know how to plan and pay for infrastructure planning and how the utility articulates that vision. But, he asked, "How do we do that in the reverse?" What is the process for managing a contraction of the system rather than an expansion? He maintained that the utilities should articulate a vision of what the goal is both for the utilities' own direct emissions and the emissions of their customers.

Catherine Yap stated that in addition to PSEP, there are TIMP, Distribution Integrity Management Program (DIMP), and Pipeline and Hazardous Safety Administration (PHMSA) requirements. These programs are the bread and butter of keeping the system safe as the Commission's Safety and Enforcement Division is very aware. This is not about building big projects; a lot of this is going to be in the context of things the utilities are required to do. In the PG&E GRC Phase One proceeding there is a list of 700 projects over a three- or four-year period that are pressure tests and replacements.

Moving to a new subject, Jean Spencer asked Mark Pocta to talk a bit more about the interstate contractual issues he mentioned. Mr. Pocta replied that there's a lot of benefit to having access to various producing basins. If the Commission is looking at shrinking the system, there are going to be trade-offs. There may be benefits to repairing and replacing infrastructure not so much to meet the design standard but to retain access to a variety of producing basins, even as the capacity of the system is reduced. Those kinds of issues are hard to develop criteria for; they almost need to be viewed on a case-by-case basis. He ended by stating that these issues may support an idea that other panelists mentioned—the need for the utilities to articulate a vision for their systems going forward as gas demand declines

Renee Guild, a senior analyst in the CPUC's Gas Policy and Reliability section, directed a question to PG&E and EDF regarding whether the utilities should be able to recover an investment in a customer's home, such as installing a heat pump, as a capital cost. She noted that cost is one of the big barriers to customers converting to heat pumps.

Byron Winget replied that capitalizing modifications to residential houses would unlock a lot of funding to start electrifying communities within current rate structures. He noted that PG&E has a $22 million project to replace eight miles of distribution line that impacts 1,200 units in the Monterey area. For $22 million dollars, PG&E could convert all 1,200 units and pay for everything—the electrical upgrade, heat pumps, new ovens, all of it. But because those costs are currently counted as expense versus capital investment, the utility can't change how the money is spent. He maintained that if PG&E could capitalize work and equipment behind the meter, there would be financial benefits for the utility and the customers.

Another question Mr. Winget raised is regarding the depreciation rate. If the gas system is shrinking, does the $22 million cost for the distribution line replacement impact ratepayers 10 years out? Does it fall onto fewer customers, or are the costs distributed between gas and electric customers and present and future customers? Now that PG&E's electric and gas GRCs have been combined, it may be possible to create a more integrated rate structure. Mr. Winget ended by noting that his comments reflected his own opinions and not necessarily those of PG&E.

Mark Pocta responded that this is a good example of how every situation is unique when it comes to the trade-offs between electrification and investment in the gas system.

Catherine Yap pointed out that electric customers face enormous burdens with all the wildfire costs and other increasing costs. She stated that if the Commission has electric customers pay for individual customers to electrify, that is going to be an enormous burden. She urged stakeholders to think through the burden on electric rates. "Costs are going up: they're going to go up in 2022; they're going to go up in 2023; and the cost of natural gas has gone up, which is causing electric rates to go up." Between transportation electrification and building electrification, stakeholders need to look at the burden being placed on electric ratepayers.

Michael Colvin responded to Ms. Guild's question about capital spending. He began by noting that a joint fuel utility might need a different strategy and different financial incentives than a single fuel utility, so the goal should be the prudent management of the decarbonization transition. The Commission might employ different shareholder signals for each utility. He then responded to Ms. Yap's point, stating that one way of managing cost increases to electric customers is by selling more units with the existing infrastructure. He agreed that electric utilities would need to build more wires and generation but maintained that a lot could be done, especially in the early years of the transition, using the existing capacity of the system. In contrast, on the gas system, if there aren't targeted incentives or changes to depreciation values or deployment of securitization or whatever rate relief strategies, the stranded asset risk and the equity risk for customers left on the gas system is very concerning. Mr. Colvin urged stakeholders to consider which customers will remain on the system and how to ensure that their rates are just and reasonable.

4.3 Panel 3: Criteria for De-rating or Decommissioning Transmission Lines

Scoping Memo Question c: what criteria should be used to determine when declining demand can enable transmission lines to be de-rated or decommissioned without harming reliability?

i. How should the Commission define a transmission pipeline vs. a distribution line?

ii. What should the regulatory process be for de-rating a transmission pipeline to a distribution pipeline?

4.3.1 CPUC, Safety and Enforcement Division

Matthewson Epuna from the CPUC's Safety and Enforcement Division (SED) began by noting that SED held a workshop on the definition of transmission pipelines in October 2018. Federal regulations define gas transmission, distribution, and gathering lines as follows.

- A transmission pipeline is defined as a pipeline, other than a gathering line, that:
    - transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;
    - operates at a hoop stress of 20 percent or more of specified minimum yield strength (SMYS); and
    - transports gas within a storage field.
- A distribution line is defined as a pipeline other than a gathering or transmission line.
- A gathering line is defined as a pipeline that transports gas from a current production facility to a transmission line or main.

Mr. Epuna noted that it is necessary to establish that a particular pipeline is not a transmission pipeline or a gathering pipeline before classifying it as a distribution pipeline. Gathering pipelines are typically easier to distinguish.

After its 2018 workshop, SED determined that the existing definition of transmission pipelines allows for differing interpretation by pipeline operators. SED determined that the primary reason for the differing interpretations is the ambiguity of the terms: "distribution center" and "large volume customer that is not down-stream from a distribution center." SED concluded that the existing transmission pipeline definitions allow operators flexibility to define what constitutes a distribution center and thus what is considered a transmission line. SED also concluded that this flexibility does not pose a threat to public safety at this time.

In 2021, the total pipeline mileage in California was divided between the different types of pipelines as follows:

- Transmission: 10,368
    - 2,879.5 miles of which are in high consequence areas (HCAs)
- Distribution: 203,000
- Services: 9,036,398
- Gathering Lines: 0

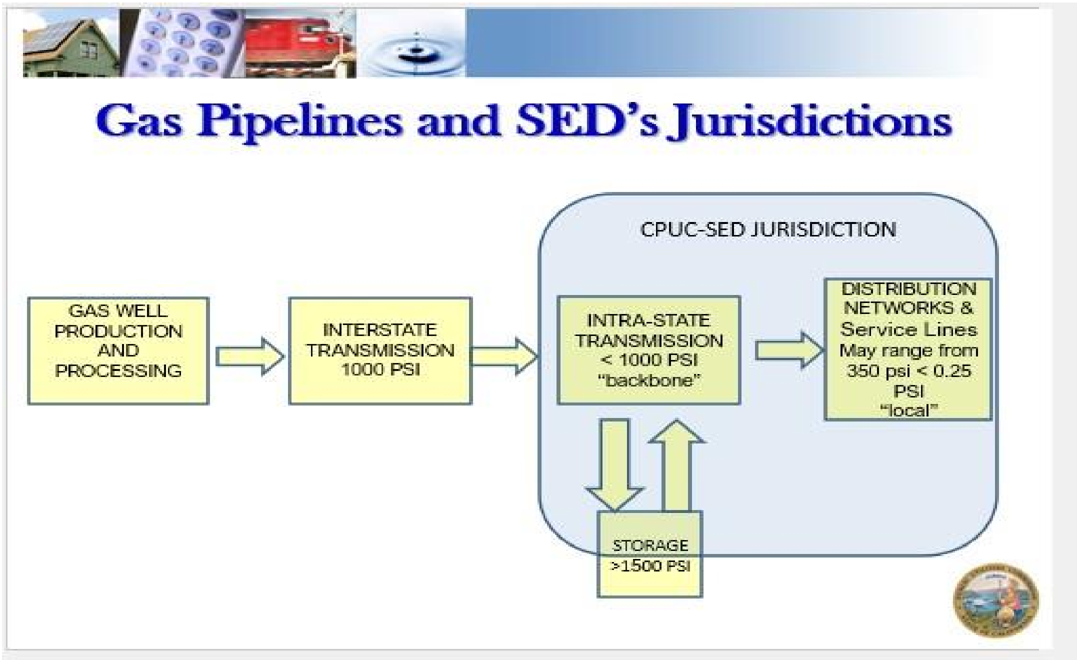
Mr. Epuna noted that there are differences in the regulatory mandates for transmission and distribution pipelines. The Transmission Integrity Management Program (TIMP) is more prescriptive, and the Distribution Pipeline Integrity Management (DIMP) is more performance based. For example, the TIMP requires a determination of whether the pipeline is in a high consequence area, inline inspection, direct assessment, and pressure testing, among other requirements. DIMP requires leak surveys, patrolling, and valve maintenance. Compliance with TIMP is considerably more expensive than compliance with DIMP.

The CPUC adopts and enforces PHMSA's Federal Natural Gas Pipeline Safety Regulations on all investor-owned utilities that operate intrastate gas pipelines and natural gas storage fields in California. These regulations prescribe minimum safety requirements for pipeline safety and the transportation of gas. The CPUC's General Order 112-F automatically incorporates these regulations.

The figure below illustrates how jurisdiction over inter- and intrastate gas infrastructure is shared between federal and state regulators. Interstate gas transmission is regulated by the Federal Energy Regulatory Commission (FERC). The CPUC shares jurisdiction over storage with the California Geologic and Energy

Management Division (CalGEM). The CPUC's jurisdiction includes the above-ground pipeline facilities and compressor stations and ends at the wellhead. CalGEM's jurisdiction begins at the wellhead and includes underground storage.

Figure 2: The CPUC's Jurisdiction Over Gas Infrastructure



To conclude, Mr. Epuna stressed that any regulatory process for derating a transmission line must address the following: 1) pipeline safety; 2) supply reliability; and 3) compliance with 49 CFR Part 192, Section 193 definitions. These include maximum allowable operating pressure (MAOP); operating pressure; percent SMYS; diameter; length; class location; and capacity.

4.3.2 Pipeline and Hazardous Materials Safety Administration

Thomas Finch, a Community Liaison for PHMSA, provided an overview of the history of the agency's "Mega Rule." It began with the 2010 pipeline explosion in San Bruno and is still underway. The Mega Rule was split into three parts. The first rule, which focused on gas transmission pipelines, was issued in October 2019. The second, which concerns repair criteria, integrity management, cathodic protection, and other related issues, is still under development. The third will focus on gas gathering lines. PHMSA's draft rules are posted in the Federal Register to solicit public comment. Mr. Finch also reviewed the definitions for different types of pipelines, noting that a large volume customer may receive a similar volume of supply as a distribution center. He concluded by describing PHMSA's process for answering frequently asked questions and posting public comments on rulemakings.

4.3.3 SoCalGas

Jonathan Peress, the Senior Director of Business Strategy and Energy Policy at SoCalGas, began by noting that many system planning considerations are driven by safety requirements, such as those prescribed by PHMSA. He stated that both state agency and SoCalGas decarbonization scenario planning forecast that while gas annual throughput will decline, peak throughput will not. He presented technical information that supplemented what Mr. Epuna and Mr. Finch presented, noting that maximum allowable operating pressure is a key consideration. The higher the MAOP, the more rigorous the requirements.

Mr. Peress stated that, in theory, de-rating from high pressure transmission to medium pressure distribution would decrease the magnitude and cost of testing, assessment, and maintenance activities. However, derating could shift current transmission asset costs to distribution customers, potentially exacerbating rate inequities. He also maintained that reducing pressure could reduce gas system resiliency, making it more difficult to compensate for unscheduled outages or other events effecting capacity and supply.

Mr. Peress discussed the need for operational integration of the gas and electric systems, stating that the gas system should be designed to meet the predicted peak needs of the system, even as annual throughput is reduced. SoCalGas decarbonization modeling suggests that peak hourly and daily takes by electric generators will continue to grow, offsetting, at peak, reductions in core gas use. Therefore, he argued, the importance of high-pressure transmission and storage will increase with decarbonization.

His presentation concluded with a recommendation that an outcome of this rulemaking should be a CPUC-reviewed and transparent integrated energy system planning process that informs the extent to which wholesale-level transmission assets can be derated as a tool to decrease customer costs without harming reliability.

4.3.4 Summary of Q&A

Commissioner Rechtschaffen directed the following question to Jonathan Peress: Even if we do need to maintain a certain level of overall gas capacity for the foreseeable future, how do we strategically reduce lines that serve certain end-uses? For example, are there places where we could selectively decommission the gas system because there aren't gas electric generators there?

Mr. Peress stated that SoCalGas' modeling does not forecast a significant portion of transmission being de-rated or decommissioned. During the CEC decommissioning workshop in November, Amber Mahoney of E3 used the term "zonal electrification decommissioning." That is the idea that targeted electrification in geographically specific regions could be combined with strategic decommissioning. SoCalGas is working with the RAND Corporation and others to validate that hypothesis and to find possible candidates. However, it's very challenging, particularly in high density or colder climate areas.

Jean Spencer of the CPUC's Energy Division asked Mr. Peress whether reducing pressure below 20 percent specified minimum yield strength was sufficient to transform a transmission line into a distribution line or whether there are other considerations that need to be taken into account to effectuate a de-rating? Mr. Peress responded that one has to look at the systemwide functions that are being served by a pipeline that is being considered for de-rating in addition to the economic implications of that prospective de-rating. He added that he was not with SoCalGas at the time of the Line 1600 discussion, but his secondhand understanding is that, when the systemwide functional analysis was done, SoCalGas proposed other upgrades that would have made up for Line 1600's services before considering it for de-rating.

Marcel Hawiger of TURN asked panelists to discuss the cost impacts of the different ways SoCalGas and PG&E define "distribution center." Mr. Peress replied that he doesn't have expertise in this area, but from his research he knows PG&E and SoCalGas define distribution centers very differently. SoCalGas functionally defines a distribution center as the place where gas comes into the state for purposes of being distributed into the SoCalGas system. This means, in effect, that all of the SoCalGas system is behind the distribution center. Mr. Peress added that, in his understanding, PG&E defines a distribution center as the interface at a regulating station between the high-pressure transmission system and a distribution center.

Ms. Spencer asked panelists for suggestions for creating a forum to define the ambiguous terms "distribution center" and "large volume customer." Matt Epuna stated that those two terms need to be defined by the Commission in conjunction with the operators. The Commission should seek input from the operators because configurations vary, and the operators will know more about how each of those configurations plays into the definition.

Bryon Winget responded to Mr. Hawiger's earlier question by noting PG&E is much more conservative in its definition of "distribution center." For PG&E, a distribution center is basically where pressure goes below 60 pounds per square inch (psi). PG&E applies transmission integrity management principles to a lot of its system that operates below 20 percent SMYS, which has a cost impact. Mr. Winget stated that PG&E spends, roughly, tens of millions of dollars annually on TIMP applied to pipelines that operate under 20 percent SMYS. He added that PG&E would be very happy if there was alignment in the state from the CPUC and that PHMSA is working on updating a definition for distribution as well.

Kevin Lang from Southwest Gas commented that PHMSA has several published interpretations that speak to the definition of a "distribution center" and transmission classification that the Commission can reference.

Matt Epuna and Thomas Finch both responded that all parties are aware of these interpretations, while Mr. Epuna noted that they don't currently clear up the ambiguity. Mr. Epuna mentioned that the American Society of Mechanical Engineers has also worked on the issue. Mr. Finch stated that if the Commission or anyone else has a specific item come up, they can file a request for interpretation. PHMSA has cut down its response time to within 60 days.

Norm Pederson of SCGC asked Mr. Epuna if it is possible to avoid creating a statewide interpretation, given the cost implications, since SED has already said there are no safety concerns about operators having differing definitions. Matt Epuna responded that, previously, SED looked only at safety. However, the concern stakeholders are dealing with in this proceeding involves other issues such as capacity, reliability, economic impacts, etc. So, from those perspectives, it will be important that those two terms be defined.

4.4 Panel 4: Criteria for Repairing or Replacing Distribution Lines

Scoping Memo Question d: What criteria should the Commission use to determine whether aging distribution infrastructure should be repaired or replaced when a gas utility requests ratepayer funds?

- i What pipeline-related characteristics should be considered when determining whether to replace distribution infrastructure (e.g., downstream impacts, pipeline's role in serving industrial (hard to electrify) load, type of customers served, customer density, age, safety condition, pipe material such as Aldyl-A, proximity to a source of renewable gas?)
- ii What community characteristics such as designation as a disadvantaged community (DAC), should be considered?
- iii What other criteria, if any, should be considered?
- iv What goals should be considered when using these characteristics (e.g., cost savings, pipeline safety, net greenhouse gas reductions, environmental justice)?
- v What non-pipeline alternatives should be considered?
- vi How should the cost of non-pipeline alternatives be compared to the cost of gas pipeline replacement or repair? For example, are there avoided operations and maintenance (O&M) and infrastructure replacement costs for retiring distribution pipelines that could be estimated and incorporated into cost-effectiveness analysis?
- vii If the Commission determines that a distribution pipeline should be decommissioned, what consideration should be given to customers who do not wish to stop their gas service?

4.4.1 Southwest Gas

Samuel Grandlienard, Manager of Operations at Southwest Gas, began by giving a brief overview of Southwest Gas' service portfolio and territories in California. He then stated that an appropriate gas infrastructure portfolio, given both California's greenhouse gas reduction laws and the utilities' obligation to serve, focuses on 1) fortification of safety, reliability, affordability, and resiliency; 2) optimization of new technology and processes to increase efficiency and reduce GHG emissions; and 3) being prepared to take advantage of advancements in gas energy that are expected to reduce GHG emissions. When determining whether to fund repair or replacement of distribution infrastructure, Mr. Grandlienard suggested that the Commission consider the following questions:

- Is system safety, reliability, or resiliency improved?
- Does repair or replacement maintain or improve energy affordability?
- Does repair or replacement prepare for advances in gas energy?

In response to Question i. regarding pipeline characteristics, Mr. Grandlienard maintained that three characteristics that should be considered when determining whether to repair or replace infrastructure are system safety, capacity, and efficiency. Through the Commission's risk-informed decision-making process, Southwest Gas is continuing to modernize its system to increase safety, meet continuing energy demands, and operate efficiently to reduce GHG emissions. He noted that 87 percent of Southwest Gas' distribution system dates from 1980 or more recently and that all PVC and Aldyl-A pipeline has been removed. He added that over the last 30 years, gas distribution pipeline mileage in California has doubled while the leak rate has gone down by 75 percent.

In response to Question ii, Mr. Grandlienard stated that a sizeable portion of Southwest Gas' California service territory includes disadvantaged communities. The following characteristics are representative of communities in Southwest Gas' territory and should be considered: socioeconomic factors (e.g., unemployment rates, ownership levels, rent burden), community types (e.g., a blend of rural and urban); geographical factors (e.g., risk of flooding, fire, drought, earthquake); and an increase of energy demand from commercial or industrial customers.

Mr. Grandlienard addressed Question iii by stating that the following objectives, or necessary conditions, must be achieved when considering community characteristics: energy system safety, reliability, affordability, and resiliency. After the necessary conditions are met, the focus should be on high-priority goals such as reducing GHG emissions.

In response to Question v regarding non-pipeline alternatives, Mr. Grandlienard stated that both energy needs and high impact events will continue to increase. Given that context, Southwest Gas recommends that the Commission fortify, optimize, and advance gas infrastructure to partner with renewables to serve growing energy needs and reduce GHG emissions. Pathways to decarbonize natural gas include upcoming advances in renewable natural gas, the Department of Energy's Hydrogen Shot,[6] and point-source carbon capture.[7]

In response to Question vi, which touches on how to compare the costs of pipelines and non-pipeline alternatives, Mr. Grandlienard noted that the operations and maintenance costs to transport and store energy alternatives should be considered. He added that non-pipeline alternative lifecycles should also be compared in a holistic manner.

In response to Question vii, regarding the consideration that should be given to customers who don't wish to stop gas service, Mr. Grandlienard stated that prudency, user choice, affordability, system resiliency, and customer education should be part of the answer. He maintained that, according to a 2019 survey, 91

[6] Hydrogen Shot | Department of Energy

[7] Point-Source Carbon Capture

percent of Southwest Gas customers preferred the choice of natural gas, adding that gas energy is consistently cheaper and more reliable during high impact events.

4.4.2 Self-Help Enterprises

Abigail Solis, Manager of Sustainable Energy Solutions at Self-Help Enterprises, a community development and affordable housing organization that helped facilitate the San Joaquin Valley Pilot program—began by addressing Question ii, which touches on disadvantaged communities. Ms. Solis maintained that DACs should be given priority due to 1) historic disinvestment; 2) higher household energy costs for low-income families; and 3) the disproportionate impact GHG emissions have on low-income communities and people of color. To mitigate these effects, the Commission should prioritize vulnerable communities, create an equitable transition, and update cost-effectiveness tests to include health, wellness, GHG reductions, and equity.

In response to Question v, Ms. Solis stated that non-pipeline alternatives should include building electrification, energy efficiency, and renewable energy. She recommended that solar be made more accessible to DACs, that opportunities for community-wide solutions be created, and that community solar and microgrids should be developed.

Ms. Solis cited the following key takeaways from the San Joaquin Valley Pilots: 1) building and maintaining trust is essential to success; 2) program barriers create limitations; 3) each home is unique; 4) project timeline should consider electric panel and infrastructure upgrades; and 5) providing appliance education and training will increase the adoption of electric appliances. During the program, Self-Help Enterprises found that participants are interested in receiving electric stoves, as well as in renewable energy, rooftop solar, and battery storage. Participation increases if people are given the opportunity to try the new appliances and as installations occur in the community.

In addressing Question vii regarding customers who may not wish to discontinue gas service, Ms. Solis suggested that a phased approach is important to address some residents' initial hesitancy toward electrification. Programs should be flexible enough to accommodate both the early adopters and those who want to wait and see how it goes for others. Robust community engagement and education through a trusted community-based organization is important in preparing residents for electrification, as they are more likely to support and participate in community led projects.

Ms. Solis gave the following suggestions for designing electrification programs, emphasizing the need for community participation:

- Consider the housing stock;
- Leverage other programs to provide better energy efficiency;
- Plan for mobile homes;
- Provide no-cost electric panel upgrades;
- Avoid delays in electric infrastructure upgrades; and
- Develop an equitable landlord-tenant agreement.

Ms. Solis concluded by recommending that the Commission 1) not allow new gas hook-ups; 2) prioritize the most vulnerable communities; 3) develop pilot projects to test recommendations; and 4) collaborate with counties, cities, schools.

4.4.3 Coalition for Renewable Natural Gas

Sam Wade, the Director of Public Policy at the Coalition for Renewable Natural Gas, began by giving a brief overview of what renewable natural gas (RNG) is and how it is produced. Greenhouse gases are captured and converted into renewable natural gas that can be used in any natural gas application. He provided references to several reports that note the importance of reducing methane emissions as a climate strategy and figures showing the growth in RNG projects in recent years.

Mr. Wade suggested that there should be a multi-phase strategy for using RNG, with a near-term strategy of reducing methane emissions, a mid-term strategy of prioritizing RNG use in hard-to-decarbonize sectors, and a long-term strategy of managing the transition to hydrogen with carbon capture and storage.

He maintained that use of RNG is critical to meeting California's climate goals because it both reduces existing methane emissions and displaces fossil gas while being complementary to electrification efforts. To be able to plan new projects, RNG developers need to know where they should be constructed in order to interconnect with the system. For this reason, Mr. Wade suggested that initial pruning of the gas system should not take place near likely locations for RNG supply. He noted that RNG supply is likely to be geographically distributed and closer to California's demand centers than fossil gas supply. RNG production and distribution could also help provide a just transition for the gas workforce, since their skills are required by the RNG industry.

In response to Question i, Mr. Wade stated that replacement of gas infrastructure should be done with materials compatible with hydrogen, where reasonable. He maintained that hard-to-electrify load needs low-GHG solutions like RNG to prevent industrial activity from shifting out of state.

In response to Question ii, Mr. Wade said that the regional availability of RNG (including future potential) should be considered, adding that determining likely locations for RNG supply should be relatively straightforward based on the distribution of organic wastes. Mr. Wade stated that the RNG Coalition supports environmental justice goals but defers to other stakeholders on prioritization based on DAC status.

In response to Question iii, Mr. Wade stated that net lifecycle GHG reduction and the state's organic waste diversion goals should be considered.

In response to Question iv on non-pipeline alternatives, Mr. Wade noted that there have been discussions in New York to treat on-system RNG as a non-pipeline alternative. Trucking RNG or generating alternative energy carriers, including electricity, can be viable when pipeline infrastructure is not locally available. However, these options are typically less efficient than pipelines.

In response to Question v, Mr. Wade referred to a recent whitepaper written by CPUC intern Anna Brockway[8] that explains the modular benefits of non-pipe alternatives, which benefit from a lower cost of capital while preserving the flexibility to avoid investments if demand patterns change, mitigating the risk of stranded assets. Mr. Wade stated that RNG trucking requires less up-front capital but likely has higher overall costs if the RNG asset is expected to be long-lived.

In response to Question vii, Mr. Wade encouraged the Commission to consider offering compensation or buyouts for remaining customers who still need gas that would help cover the costs of trucked RNG or other solutions. He reiterated the need to avoid pushing economic activity out of state, noting that doing so would simply push emissions to another jurisdiction.

[8] Gas Planning and Reliability in California: [gasplanning_final_2021-12-27.pdf (ca.gov)]

4.4.4 The Utility Reform Network

Marcel Hawiger, a staff attorney at The Utility Reform Network (TURN), focused his presentation on questions i, iv, and vi. He provided data from PG&E's current GRC to highlight existing criteria for repairing and replacing distribution pipelines.

Mr. Hawiger began by presenting his preliminary conclusions. He stated that the current criteria for *repairs*, which are focused on safety and GHG reductions, are appropriate in the near term and do not increase the risk of stranded assets. He noted that the current criteria for pipeline *replacement* are based on safety and pipe material, adding that what is needed is not new criteria but proper safety risk modeling that prevents unnecessary replacements and reduces the risk of stranded costs. Mr. Hawiger also suggested that Question vi, which focuses on cost comparisons between pipeline and non-pipeline alternatives is premature. He maintained that the first step is to address how non-pipeline alternatives can be actual alternatives that reduce the need to repair or replace distribution pipelines.

Focusing in on PG&E's current GRC, Mr. Hawiger noted that repair expenses are forecasted to increase from $105 million in 2020 to $132 million in 2023 due primarily to repairs of non-hazardous leaks to reduce methane emissions. Mr. Hawiger stated that repairs are primarily categorized as expense, so they increase current gas rates but do not increase the risk of stranded assets. He maintained that the repair criteria based on safety are appropriate while the criteria based on methane reduction may be appropriate, but there isn't sufficient data to show conclusively that the reduction in GHG emissions from meter sets is cost effective.

PG&E is also forecasted to spend about $3.4 billion on replacing distribution pipelines during the 2023 to 2026 rate case cycle. This spending is mostly driven by its goal of replacing pre-1985 Aldyl-A pipes due to safety considerations based on its risk analyses. He noted that PG&E's distribution pipeline replacement program is discretionary unlike mandatory programs such as DIMP. The criteria PG&E focuses on are primarily age and pipeline material. In response to Question i: Mr. Hawiger's preliminary conclusion is that the current focus on safety in pre-emptive replacement criteria is generally appropriate and that there is no need for using a different criterion. He added that the key problem is not the criteria; rather it's having a proper goal to determine the pace of pre-emptive replacement.

In response to Question iv, Mr. Hawiger suggested that the primary goal in choosing criteria for repair and replacement should be to reduce potential future stranded costs on the gas system. He stated that there is a need to balance the safety benefits of large-scale pre-emptive replacement of plastic pipe on the distribution system with minimizing the stranded costs. This type of balance would require better data with a prioritization model that focuses on finding the riskiest pipelines that need to be immediately replaced.

In response to Question vi on comparing pipeline and non-pipeline alternatives, Mr. Hawiger suggested that the question is premature. The first step is to determine how building electrification can be done so that it avoids repair or replace costs on the gas system. In order to avoid *repair* costs, the utilities should focus on portions of the system that have high leak rates and are scheduled for repairs. They must also electrify a sufficient portion of a geographically contiguous system so that distribution pipeline can be eliminated. In order to avoid *replacement* costs, utilities would need to select a portion of the system where the pipe has similar characteristics and, again, electrify a large enough geographic area that an entire section of distribution pipeline could be eliminated.

Mr. Hawiger also stated that the first step is to stop growing the problem by avoiding new gas hook-ups. He found the Commission's proposal to eliminate gas line extension allowances to be a good first step. However, he pointed to forecasts of significant, ongoing capital expenditures for new customers connections in PG&E's rate case as evidence that more needs to be done. Mr. Hawinger advocated for major changes to prevent new gas hook-ups, whether at the state or local level. He added that relying on subsidizing individual customers to electrify is not a solution that can be adopted at scale. A method that should be considered to address building electrification on a significant scale would be to require existing buildings to be electrified upon sale.

4.4.5 Gridworks

Claire Halbrook—the Director of Gridworks, a non-profit organization focused on decarbonization—recommended that the CPUC first develop a broader, long-term gas planning framework with clearly defined objectives and a process for achieving those objectives. It should also include a strong focus on evaluating and implementing pipeline in a timely fashion.

In response to Scoping Memo Question d, Ms. Halbrook stated that, given California's recent focus on gas pipeline repair and replacement alternatives, Gridworks cannot definitively provide a data-supported answer at this time on the implications of selecting certain criteria over others. However, she maintained that there is a robust process established to develop answers to these questions. The CEC recently sponsored a new project focused on developing strategic pathways and analytics for tactical decommissioning of portions of the gas infrastructure.[9] The Northern California project intends to 1) create a framework for evaluating and characterizing gas decommissioning opportunities within the PG&E and East Bay Community Energy (EBCE) shared service territory; 2) engage local communities and identify needs with respect to participating in gas decommissioning and targeted electrification pilots; 3) recommend three pilot sites for targeted gas decommissioning, including one in a disadvantaged community; 4) produce deployment plans for each pilot site, indicating how to implement targeted decommissioning and electrification in those areas; 5) produce deployment plans for each pilot site, indicating how to implement targeted decommissioning and electrification in those areas; and 6) produce deployment plans for each pilot site, indicating how to implement targeted decommissioning and electrification in those areas.

Other initiatives that may help answer Question d would be PG&E's projects to explore and implement pipeline repair and replacement alternatives as well as developing a more robust framework for identifying and prioritizing pipeline alternative projects. In addition, Ms. Halbrook stated that the San Joaquin DAC pilot program[10] can provide important insights on how to center equity when developing policies that can significantly impact individuals.

To conclude, Ms. Halbrook stated that there needs to be a strong emphasis on advancing pipeline alternatives. To improve customers' familiarity and comfort with alternative technologies, the Commission should remove regulatory barriers that slow implementation and address funding gaps that go beyond simply replacing customer appliances.

4.4.6 Summary of Q&A

Commissioner Rechtschaffen asked Marcel Hawiger to elaborate on why he thinks it's premature to look at the cost of non-pipeline alternatives. Mr. Hawiger clarified that the way he understood the question was to determine what benefits and costs should be included in the standard cost-effectiveness analysis, which can be done readily. For example, the San Joaquin Valley Pilot gives insight into how much it costs to electrify different type of homes. And, as mentioned in Mr. Hawiger's presentation, he believes that the Commission must first determine how building electrification can be done in an efficient way to avoid repair or replacement costs on the gas system.

[9] https://www.energizeinnovation.fund/projects/strategic-pathways-and-analytics-tactical-decommissioning-portions-natural-gas

[10] San Joaquin Valley DAC Pilot Presentation

Commissioner Rechtschaffen observed that Samuel Grandlienard's presentation valued decarbonization last and instead focused first on safety, reliability, affordability, and resiliency. Mr. Grandlienard responded that it's an interesting balance to meet a climate goal while not exceeding costs or going over safety thresholds.

Mr. Grandlienard was also asked if Southwest Gas is in favor of increasing the monthly meter charge to its residential customers to lessen volumetric charges. Mr. Grandlienard responded that Southwest Gas is open to the discussion, but affordability must play a central role. In Southwest Gas' recent GRC, the company received approval for an increase in the basic service charge to better reflect customer-related costs and to assist in decreasing peak winter monthly bills.

Sam Wade was asked whether RNG will ever be produced in sufficient volumes to provide 20 percent of the load currently being served by fossil gas. Mr. Wade stated that RNG will be able to provide a very significant portion of the long-run demand for gas. If alternatives are successful in cutting gas demand, then the share that can be served by RNG gets larger.

Mr. Hawiger was asked how he would weigh the benefits of boosting overall electrification from a policy requiring electrification on sale of a residence with the potential to increase housing costs in a state with a shortage of affordable housing. Mr. Hawiger stated that this was a question that TURN had struggled with internally. The answer depends on whether California is serious about going to scale up electrification by 2045. The information he has seen indicates that electrification costs range from $20,000 to $50,000 per home. If California wants to go big on electrification, what are the options? If electrification costs are subsidized through bills, it will bankrupt people through rates. "If you're going to go big, somebody has to pay for it," he said, "and I don't think having utility customers fully subsidize home retrofits is any better of an answer." He noted that a current Commission proposal to require that 15 percent of core load be served with RNG will also cost core customers an extra billion dollars a year. That won't lead to stranded costs, but it will greatly increase rates. In this context, electrification should be addressed through gradual state mandates that allow for a transition period to reduce impacts on lower-income households.

In response to Mr. Hawiger, Abigail Solis noted that, although she does not want to decide who should subsidize the cost, there was a situation in the San Joaquin Valley Pilot program in which a homeowner was able to sell their property at a higher price after electrifying the home.

4.5 Summary of Final Q&A

Marlon Ferguson with the Natural Resources Defense Council (NRDC) posed a question for Commissioner Rechtschaffen, "What is your vision for how we get from discussing these questions to a comprehensive gas planning process with clear goals as described by Claire from Gridworks?" Commissioner Rechtschaffen explained that the CPUC is working systematically through threshold issues in the first couple of tracks but will continue to work with sister agencies, the Legislature, and the Governor's Office to create a roadmap to tackle this more holistically. He added that the CPUC will benefit from learning about the ongoing pilot programs and research done by the CEC and other states.

Jonathan Bromson, a lawyer at the CPUC commented, "On the topic of electrification, the New York State Governor just proposed $25 billion to electrify 800,000 homes owned by low- and moderate-income homeowners. That's $32,250 per household by 2030. Over 11 million California homes need conversion."

A question in the chat asked, "Given that LADWP [Los Angeles Department of Water and Power] isn't CPUC regulated, how can joint planning occur with SoCalGas on decarbonization of SoCalGas' system when LADWP doesn't have any obligation to work with Commission-regulated utilities?" Jonathan Peress of SoCalGas explained that LADWP will be subject to the emission control requirements that are imposed upon it by regulators with actual jurisdiction over emissions. He added that emissions on SoCal Gas' system result from independent decisions made by customers to procure gas and combust it. Most of those customers, and the emissions resulting from their activities, are outside the jurisdiction of the CPUC.

Matt Epuna of the CPUC's Safety and Enforcement Division asked if any of the panelists have data on the monthly usage cost for an electrified residence compared to a unelectrified residence. In response, Abigail Solis noted that her organization is actively collecting that data in the San Joaquin Valley Pilots. As part of the program, PG&E provides residents with a proposed plan that gives the home an estimate of electric costs after electrification compared to their current propane costs. That data should be available in about one year. Marcel Hawiger added that the only report he's seen with that analysis is from the Rocky Mountain Institute. The analysis shows that homes that replaced both heating and cooling saw bills go down. In homes where just heating and water heating were replaced, bills went up.

A question in the chat asked whether alternative energy forms, such as using hydrogen gas as a fuel, will be considered during the General Order 131-D review. If not, when and how will these alternatives be considered? Mary Jo Borak of the CPUC's CEQA section stated that the Commission does not look at hydrogen as part of GO 131-D.

Elizabeth Kelly with EDF asked Ms. Borak if a General Order is adopted, how she envisions non-gas or non-pipeline alternatives within that context and whether it would it be an element of the General Order. Ms. Borak responded that any General Order that would deal with gas facilities would have to decide how broad the review and discussion should be. When conducting environmental impact reviews of electric facilities for transmission lines, the Commission does look at non-wire alternatives.

5 TRACK 2 WORKSHOP 2 GAS INFRASTRUCTURE

5.1 Panel 1: Criteria for Decommissioning Distribution Lines

Scoping Memo Question e: What criteria should be used to determine which distribution lines should have the highest priority for decommissioning?

i. What pipeline-related characteristics should be considered when prioritizing distribution lines for decommissioning (e.g., age, safety condition, pipeline's role in serving industrial (hard to electrify) load, extent to which it has been depreciated, location, customer density, pipe material such as Aldyl-A, proximity to a source of renewable gas)?
ii. What community characteristics, such as designation as a DAC, should be considered?
iii. What other criteria, if any, should be considered?
iv. What goals should be considered when using these characteristics (e.g., cost savings, minimizing stranded assets, pipeline safety, net greenhouse gas reductions, environmental justice)?
v. What non-pipeline alternatives should be considered?
vi. How should the direct and indirect costs of non-pipeline alternatives be compared to the cost of replacement? For example, are there avoided O&M and pipeline replacement costs for retiring distribution pipelines that could be estimated and incorporated into cost-effectiveness analysis?
vii. If the Commission determines that a distribution pipeline should be decommissioned, what consideration should be given to customers who do not wish to stop their gas service?

viii. What planning and procedures are necessary to ensure that there is sufficient local electric capacity available to reliably serve customers that move off the gas system?

ix. Are there health and safety issues that need to be addressed from decommissioned distribution lines?

x. What procedural mechanism should be used to proactively decommission distribution lines?

5.1.1 CPUC Energy Division

Jessica Allison, a senior analyst on the CPUC's Building Decarbonization and Renewable Gas Team, began by noting that she was not speaking for the Commission. She stated that the primary non-pipeline alternative to natural gas infrastructure is building electrification. She suggested the following goals for targeting pipeline decommissioning: 1) maximizing public safety; 2) minimizing disruption to Californians, e.g., making people feel that the transition is natural rather than forced; and 3) transitioning to a lower GHG future at the least possible cost. Focusing on pipelines where favorable factors intersect may maximize investment benefits. An ideal community may be one with aging gas infrastructure and without electrical capacity constraints in a climate zone that maximizes the cost-effectiveness of heat pumps.

Community characteristics should include: 1) customers should have informational, technical, and financial support to transition to electric end uses; 2) the electric grid should have generation, transmission, and distribution capacity to handle an influx of electric load; and 3) electric rates should be affordable, considering both the cost of service and customer ability to pay.

To minimize customer disruption, home and business electrification must occur prior to pipeline decommissioning. Ms. Allison suggested that the Commission prioritize communities with high existing electric heating, ventilation, and air conditioning (HVAC) and water heating penetration, as they may require less transformation to be ready for pipeline decommissioning. Her other recommendations included targeting customers with high existing air conditioning utilization, early adopters, and communities bordering rural areas. With respect to rural areas, she stated that delivering gas to more rural communities may require more infrastructure with fewer customers over which to spread the costs. She also referenced her own experience living in such a community where heating is primarily served by propane. She said that contractors in her area are more familiar with heat pumps because they are one of only two choices for heating.

Ms. Allison stated that it is critical that communities identified in the CPUC's Environmental and Social Justice Action Plan not get left with the cost of stranded infrastructure. At the same time, disadvantaged communities shouldn't bear the burden of hasty electrification, premature pipeline decommissioning, or lack of choice. Whenever such communities meet the other criteria for pipeline decommissioning—i.e., support for a transition away from natural gas, electrical grid sufficiency, and affordable electric rates—they should be prioritized. If those conditions don't appear organically as the state gains experience with electrification, they may need to be created.

When considering pipeline characteristics, Ms. Allison said that public safety is the first and most critical consideration. Safety issues are affected by age and pipeline material, such as Aldyl-A. Injecting hydrogen into the pipeline creates an opportunity for renewable power-to-gas but presents new safety challenges. Decommissioning pipelines that pose future public safety threats or prevent the evolution of the gas grid should be prioritized.

Ms. Allison maintained that avoiding costly pipeline replacements and repairs is a secondary objective to protecting public safety. The Commission should seek to maximize the value of infrastructure investments and reduce the chance of wasted future investment as policies evolve. Exceptions may be necessary for pipelines that serve hard-to-electrify industrial end uses, communities with serious electrical capacity constraints, or other challenging conditions.

5.1.2 California Energy Commission

Qing Tian is a Senior Engineer in the California Energy Commission's (CEC) Gas Research and Development Group, which oversees a $24 million per year gas public research fund. Mr. Tian set the context by noting that California's gas infrastructure is aging, the cost of replacing aging pipelines is high, gas demand is expected to decline, and the combined impact of these factors could negatively impact ratepayers and worsen equity issues. Tactical decommissioning of gas infrastructure can help maintain gas system safety and resilience while minimizing the impact on ratepayers.

Mr. Tian discussed a pilot study that will be launched later this year to develop criteria and a framework for selecting gas decommissioning sites. The study will explore methodologies and develop deployment plans for strategic decommissioning that balances decarbonization, consumer acceptance and safe operations. It will also identify community priorities, perspectives, and paths forward on electrification and gas decommissioning and identify opportunities to achieve gas system cost reductions through tactical decommissioning. Two successful bidding teams were selected, one from Southern California and one from Northern California.

The CEC has another grant funding opportunity to develop a data-driven tool to support strategic and equitable gas decommissioning, identify promising sites, determine data needs, and deliver the information in a way that is accessible to communities.[11] The deadline to submit applications is February 25, 2022.

Future research may include scaling-up the gas decommissioning pilots that will be conducted in Northern and Southern California in 2022-23; facilitating large-scale pruning of distribution-level segments, including in under-resourced communities; and supporting strategic gas transition investments for disadvantaged and low-income customers. An enhanced planning tool may also be developed, that would: 1) facilitate planning across a range of time horizons; 2) consider the cost impacts of gas and electricity system interactions; 3) analyze the potential roles of emerging zero-carbon energy sources; and 4) assess consumer and community-level energy choices.

5.1.3 PG&E

Mike Kerans, PG&E's Director of Gas Distribution Integrity Management, stated that PG&E supports proactive decommissioning of gas distribution mains and services where it reduces GHG emissions, is cost effective for individual customers, and maintains a safe and reliable energy system with appropriate and equitable cost recovery. A decommissioning project should offer attractive non-pipeline alternatives to customers through outreach and education on the various opportunities that different energy solutions can provide while meeting PG&E's obligation to serve. The utility seeks partnerships with communities and organizations in meeting the needs of DACs and local economies.

Mr. Kerans provided a three-pronged response to Question e, discussing different proactive decommissioning criteria for gas service lines, combined mains and services, and zonal efforts. Mr. Kerans stated that service lines should be decommissioned once the impacted customer or customers have converted to electric appliances. The criteria for service lines should be community and customer interest in decommissioning to support long-term community objectives for economic, equity, and environmental concerns. The criteria for decommissioning mains and service at the same time should be risk reduction,

[11] Development of a Data-Driven Tool to Support Strategic and Equitable Decommissioning of Gas Infrastructure: https://www.energy.ca.gov/solicitations/2021-11/gfo-21-504-development-data-driven-tool-support-strategic-and-equitable

customer feasibility, affordability, and the impact to customer bills. For zonal decommissioning, the criteria should be customer feasibility, affordability, and risk reduction. The overall goals for proactive decommissioning include reducing system risk, avoiding stranded assets, and ensuring intergenerational equity for gas distribution asset cost recovery.

With regard to the pipeline characteristics that should be considered when prioritizing distribution pipelines for decommissioning, Mr. Kerans provided the following categories of criteria: risk reduction, feasibility, affordability, reliability and resiliency, and geography. In the risk reduction category, a pipeline's age, safety, asset condition, and material type should be considered. For feasibility, the criteria should be customers' willingness to switch to alternative energy sources, the number and type of customers involved in the decommissioning project, and whether those types of customers are able to electrify or switch to an alternative fuel source. For affordability, Mr. Kerans recommended that the criteria should be the cost neutrality of the project when compared to decommissioning, noting that cost neutral projects tend to be in low density areas. In the geography category, a pipeline's location in relation to the overall gas system is important. For example, the tail ends of pipeline systems are easier to decommission.

In terms of community characteristics, such as designation as a DAC, Mr. Kerans emphasized the importance of support by local governments to meet the state's climate goals while balancing economic challenges, equity, and environmental concerns as well as the impact on local customers. Another consideration is the availability of community funding sources to support customer upgrades.

Mr. Kerans placed pipeline safety first among the goals that should be prioritized while also noting the importance of cost savings; net GHG reductions; the cost to, and environmental impact on, vulnerable customers; intergenerational and socioeconomic equity, including mechanisms to address phased departures from the gas system; and avoidance of stranded assets.

Non-pipeline opportunities include electric and thermal solar, building electrification, microgrids in combination with portable fuel trucking (LNG, H2, CNG) for large industrial customers, and propane. In cases where it isn't possible to decommission a pipeline segment, Mr. Kerans identified the following opportunities to reduce GHG emissions and bill impacts: hydrogen and RNG, fuel switching from dirtier fuels to natural gas, increased energy efficiency, and gas demand response programs.

To compare the costs and benefits of non-pipeline and pipeline alternatives, Mr. Kerans recommended that an economic analysis of costs and benefits should be performed that includes pipeline deactivation and retirement costs, electric system upgrades, cost of customer appliances and panel upgrades, and O&M costs. He noted that a sample of how this could be performed can be seen in PG&E's RAMP testimony. He also stated that PG&E currently performs this type of non-pipeline alternative comparison with its transmission projects and is developing similar processes for gas distribution projects.

In response to the question regarding the consideration that should be given to customers who do not wish to stop their gas service, Mr. Kerans recommended that the utility's "obligation to serve" be interpreted to allow operators to provide energy service under the same terms and conditions offered to all customers. He also suggested extensive customer outreach and communication to promote an energy transition; the use of off-system fuel sources that meet customer's needs prior to stopping gas service; and, if feasible, consider applying costs to customers who do not wish to stop gas service.

Mr. Kerans provided several recommendations for planning and procedures to ensure there is sufficient local electric capacity as customers move off the gas system. First, he suggested that the Commission establish a consistent mileage retirement rate for gas distribution mains and services to support predictable planning. Second, multi-year, forward looking plans should be developed based on the retirement rate to enable gas, electric, public works, and customer coordination. Third, capacity studies should be implemented for both gas distribution and electric systems (PG&E or non-PG&E) to ensure sufficient reliability in both systems during the multi-year transition while also planning for electric vehicle adoption and other capacity needs. Lastly, the costs of decommissioning gas distribution system and electric capacity upgrades should have an established cost recovery process.

Mr. Kerans mentioned several health and safety issues that should be addressed if distribution pipelines are decommissioned. The needs of first responders—such as hospitals, police, and firefighters—as well as commercial customers who use gas as an emergency backup fuel should be addressed. When planning upgrades of residential buildings of varied age and conditions, the safety of the customer-owned electric system should be considered. Another factor is energy reliability and resiliency during power outages. Lastly, utilities need to follow existing pipeline deactivation practices related to health and safety.

Pilot projects are one of the procedural mechanisms that should be used to proactively decommission distribution pipelines. Such projects would generate data and insights into costs and other issues and provide insights into zonal decommissioning. Mr. Kerans recommended that all pilots include at least one multi-customer project. He also advocated for the development of analytical tools to evaluate the costs and benefits of decommissioning infrastructure and a feasibility scoring system. He suggested separate funding for safety-related projects and non-risk-driven proactive decommissioning projects. The non-risk-driven projects should then be ranked. Lastly, the Commission should adopt a predictable pace and timeline aligned with appropriate cost recovery proceedings.

5.1.4 California Environmental Justice Alliance

Jina Kim, a lawyer with the California Environmental Justice Alliance (CEJA), CEJA recommended that the criteria for determining which pipelines have the highest priority for decommissioning should be determined by the end goals of reducing GHG emissions, reducing rate base, equity requirements, and affordability. She maintained that stakeholders "need a better statement from the Commission as to what its end-goals are in proactive decommissioning." For GHG goals, she suggested that the Commission look to the California Air Resources Board's (CARB's) Scoping Plan for GHG emission reductions and the Commission's Integrated Resources Plan (IRP) Proceeding, as well as other CPUC-related proceedings.

Ms. Kim stated that procedural mechanisms require equity, which in turn requires meaningful community outreach and input, working with trusted community-based organizations (CBOs), the use of understandable and accessible language, an objective and transparent process, and meaningful notice.

Ms. Kim also stressed the need for pilots. She added that pilots can provide vital information on consumers' reliability needs as well as how to protect low-income customers. The San Joaquin Valley pilots are a good model because they emphasized community engagement and accommodated different types of customers, including renters, who face different barriers to adoption.

5.1.5 Q&A

Commissioner Rechtschaffen asked Mr. Kerans if he understood correctly that PG&E was recommending a broad interpretation of the obligation to serve. Mr. Kerans answered that a broader interpretation would give the utility more flexibility to conduct pilots.

Commissioner Rechtschaffen also asked about a PG&E program to replace all pre-1995 plastic pipe that Marcel Hawiger of TURN had mentioned in the January 10 workshop. Mr. Kerans responded that Mr. Hawiger was referring to the Distribution Integrity Management Program, which is a federally mandated, risk-driven program that looks for ways to eliminate the riskiest pipes in the system. He noted that PG&E also looks for ways to move to electrification in such cases.

Commissioner Shiroma noted that she is the Assigned Commissioner for the California Alternate Rates for Energy (CARE) program and the Energy Saving Assistance Program, which is funded by gas ratepayers and replaces low-income customers' gas appliances with high-efficiency appliances. She asked whether there is any connection between that program and PG&E's non-pipeline alternatives and replacement efforts. Mr. Kerans responded that he is not familiar with that program.

Commissioner Rechtschaffen asked Ms. Kim to comment on a dilemma noted by Jessica Allison—the Commission doesn't want to force low-income consumers off the gas system and yet also doesn't want them to be the last customers on the system, facing the greatest impact from rate increases. Ms. Kim responded by saying that this underscores the need to prioritize DACs in the gas transition from the very beginning. Deborah Behles of CEJA added that it's critical to have community buy-in and community education.

In response to a question asking how the different factors in proactive decommissioning should be weighed, Mr. Kerans stated that there will be different weightings and criteria and different goals for different communities.

Marcel Hawiger of TURN asked: "How do we address electrification when replacing heat and water heating gas appliances appear to raise energy costs, unless there is an existing central heating and cooling system?" Ms. Allison responded that there might be multiple answers, including load shifting.

5.2 Panel 2: Meeting the Needs of Hard-to-Electrify Customers

Scoping Memo Question f: What infrastructure is needed to fulfill the needs of customers who are likely to remain on the gas system the longest, such as electric generators or difficult-to-electrify industrial users?

Scoping Memo Question j: How should the Commission consider the need for gas infrastructure that may be needed to serve new industrial gas customers in difficult to electrify sectors as part of the long-term gas system planning process?

5.2.1 Independent Energy Producers

Jan Smutny-Jones, the CEO of the Independent Energy Producers Association (IEP), began by calling natural gas infrastructure the "circulatory system" for California's economy. It balances the clean energy portfolio, providing generation to supply energy during net peaks, winter ramps, variations in intermittent energy sources, and monsoonal periods in winter, when California can have seven to 10 days of cloudy weather that impacts solar production. Mr. Smutny-Jones maintained that gas infrastructure delivers an essential commodity to all sectors of the economy, adding that it should be repurposed to preserve rights of way for transporting hydrogen, biofuels, and carbon capture and utilization to meet California's GHG goals.

Mr. Smutny-Jones provided examples of natural gas' ability to provide electric generation when needed, noting that, in 2020, natural gas generated 43 percent of total in-state generation. On August 14, 2020, during the heat wave that led to rolling blackouts in California, natural gas supplied 60 percent of the net peak needs. He maintained that natural gas is essential in meeting the three-hour winter evening ramp, which is currently 15,000 MW and is expected to increase to 25,000 MW by 2030. Mr. Smutny-Jones also stated that the Commission's Integrated Resource Plan identifies the need for natural gas generation through 2045, which will require existing natural gas infrastructure.

Mr. Smutny-Jones recommended that existing gas infrastructure be preserved and re-purposed. He noted that some natural gas plants that may be critical to local reliability, including municipally owned facilities, are located on low-pressure local gas lines. He also stated that some natural gas generators are exploring converting to hydrogen, other biofuels, or carbon capture, and will need the natural gas infrastructure. Billions of dollars have been invested in the natural gas infrastructure, which should not be put to waste. He compared the gas system to Southern California's urban railroad system, which was once the largest in the world. The railways were replaced with freeways, and their rights-of-way were lost. Now that regional transit is back in fashion, it's clear how valuable those rights-of-way were. Gas lines and their rights of way are similarly valuable.

California is the world's fifth largest economy and a global leader in climate change reduction. Mr. Smutny-Jones argued that the state needs to prove it can continue to be both. Using natural gas as part of California's energy portfolio has helped move the electric sector from about 23 percent to less than 14 percent of the state's carbon footprint. He stated that natural gas will continue to be necessary in transitioning to a lower carbon future. Gas infrastructure needs to be available, safe, and ready to meet the needs of all Californians.

5.2.2 Vista Metals

Shane Seever, a Director at Vista Metals and a Board Member of the California Metals Coalition, described his company as an aluminum recycler that produces aviation-grade aluminum primarily for the aerospace industry. Located in Fontana, it has 268 employees, including 188 members of the United Steelworkers Union. The company's products contain more than 50 percent recycled aluminum, which is mostly recovered from local markets. Mr. Seever noted that it is more efficient to recycle the metal in the market where it was used rather than having to incur shipping fees. Recycling aluminum uses only about 10 percent of the energy of producing a new pound. He stated that because the company must comply with California's air quality regulations, it uses state-of-the-art equipment and has the lowest emissions footprint in the industry, worldwide.

Vista Metals has eight melting furnaces, each of which hold about 100,000 pounds of metal and have 16 to 24 million British thermal unit (MMBtu) per hour burner ratings. They also have eight homogenizing furnaces, which hold about 200,000 pounds of metal and have 2-16 MMBtu/hour burner ratings.

Mr. Seever stated that Vista's business doesn't exist without natural gas as the primary energy source. Electric heating is not a viable substitute to natural gas heating for aluminum melting facilities. Mr. Seever further stated that if the plant were to electrify, its maximum demand would increase from about 2.5 MW to 90 MW. Using the company's production and utility data from 2019 to 2021, Mr. Seever calculated that purchasing the electric energy equivalent of the natural gas they use would increase the company's energy costs about sixfold. He maintained that such a cost increase could not be passed on to their customers, noting that gas service is necessary if California wants to retain manufacturing activities.

Vista Metals has had multiple discussions with SoCalGas about trying a blend of hydrogen in their gas supply, using one of the furnaces to test various hydrogen blends. However, Mr. Seever expressed concern that using hydrogen as a fuel could impact the quality of the metal because molten aluminum absorbs hydrogen. He displayed the photos below to illustrate what hydrogen does to their product. Other potential problems with using hydrogen identified by Mr. Seever include increased NOx pollution and decreased productivity. Lastly, he mentioned that the Vista Metals facility would have logistical challenges safely managing large trucks delivering hydrogen because their existing equipment takes up most of the footprint, and the facility cannot expand due to the cost of real estate.

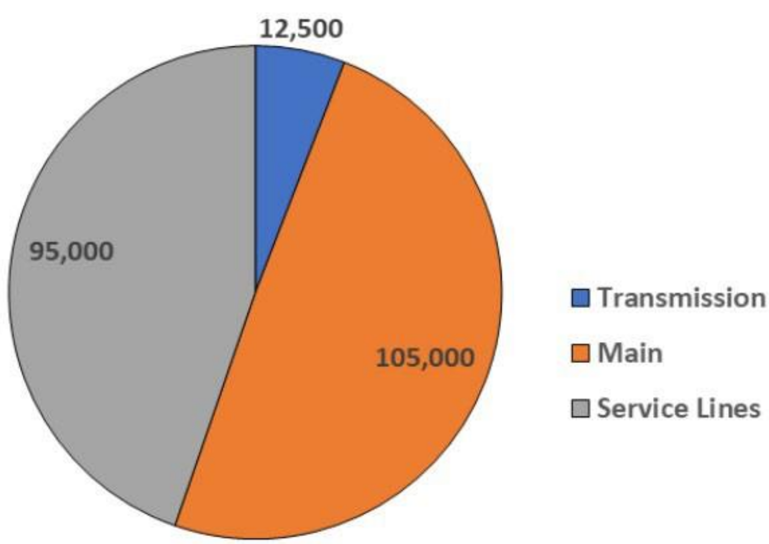
Figure 3: Aluminum with High Dissolved Hydrogen (left) and Low Dissolved Hydrogen (right)

5.2.3 UC Irvine

Dr. Jeff Reed, the Chief Scientist for Renewable Fuels and Energy Storage at UC Irvine, began by describing his university's Decarbonized Gas Research Program. The program focuses on three research areas: production, transport and storage, and end use. For production, research centers on production economics, technology forecasting, grid modeling, long duration storage, and renewables firming. In the area of transport and storage, the focus is on hydrogen injection and blending, system impacts such as leakage and pipeline embrittlement, the hydrogen carrying capacity of the gas system, and optimal pathways for deep decarbonization of the gas system. For end uses, study includes transportation decarbonization, the hydrogen tolerance of burners, and emissions impacts at the device and macro level.

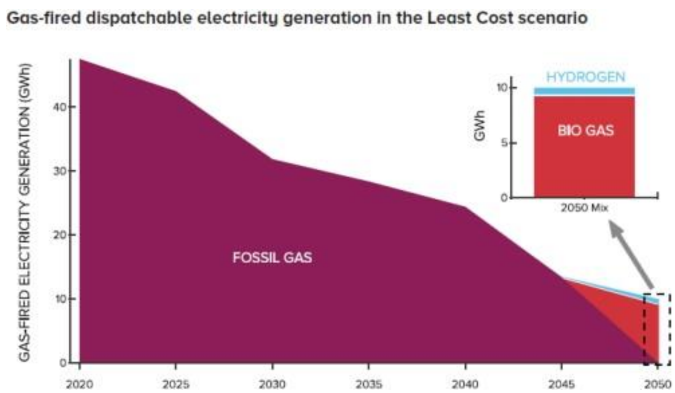
Dr. Reed stated that renewable gas of some kind will be critical to firming the electric system going forward, since an on-demand resource is needed to balance intermittent renewables. Since most gas-fired electric generators are on the gas transmission system, he maintained that transmission pipelines, as well as storage, will likely be needed over the long term. However, transmission is a relatively small part of the pipeline system at just 6 percent of total pipeline miles, as can be seen in Figure 4 below.

Figure 4: California Pipeline Miles by Type



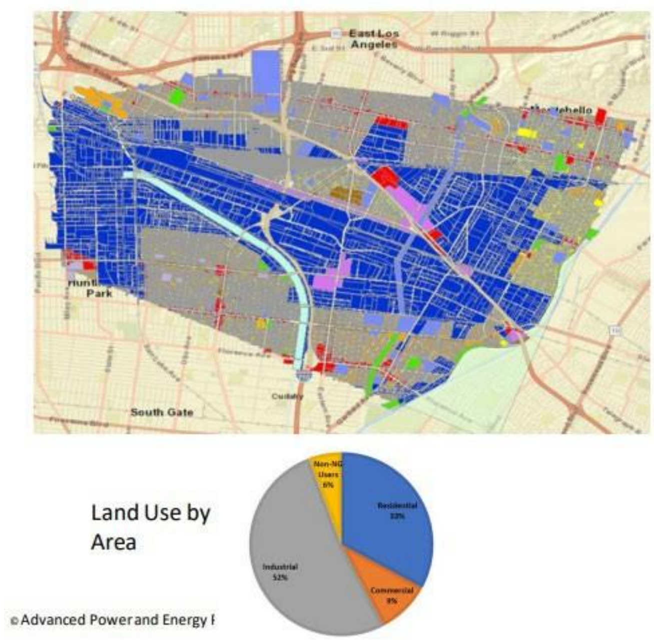
Dr. Reed referred to the New Jersey Energy Master Plan Least-Cost Scenario, which forecasts a significant decline in fossil-fueled gas generation by 2045 and modest increases in both biogas and hydrogen by 2050 (see Figure 5 below). Both the United Kingdom and Continental Europe are also leaning strongly toward repurposing their transmission system to hydrogen. Dr. Reed maintained that even though doing this would cost several billion dollars, "when amortized over the amount of fuel that would be flowing, it's actually pretty affordable." He added that renewable gas-fired generation would need enhanced emissions controls and suggested that emissions be included in the dispatch order.

Figure 5: New Jersey Energy Master Plan Least-Cost Scenario



Dr. Reed also showed several maps of Downtown and East Los Angeles, the Moreno Valley, and Santa Clarita to make the point that different types of end-users are intertwined in many jurisdictions. Therefore, it may be necessary to retain some distribution pipelines because there are industrial loads in many, if not most, zip codes. Figure 6 below provides an example of one such map.

Figure 6: Land Use by Area: Downtown Los Angeles



In conclusion, Dr. Reed emphasized the need for equitable access to alternative gas fuels, consideration of customer preferences, the potential to repurpose gas infrastructure for hydrogen, and the value of deferring decisions on decommissioning until the outcome of technological progress is clearer. He also stated that if portions of the gas system are mothballed, the option should be left open to recommission them later.

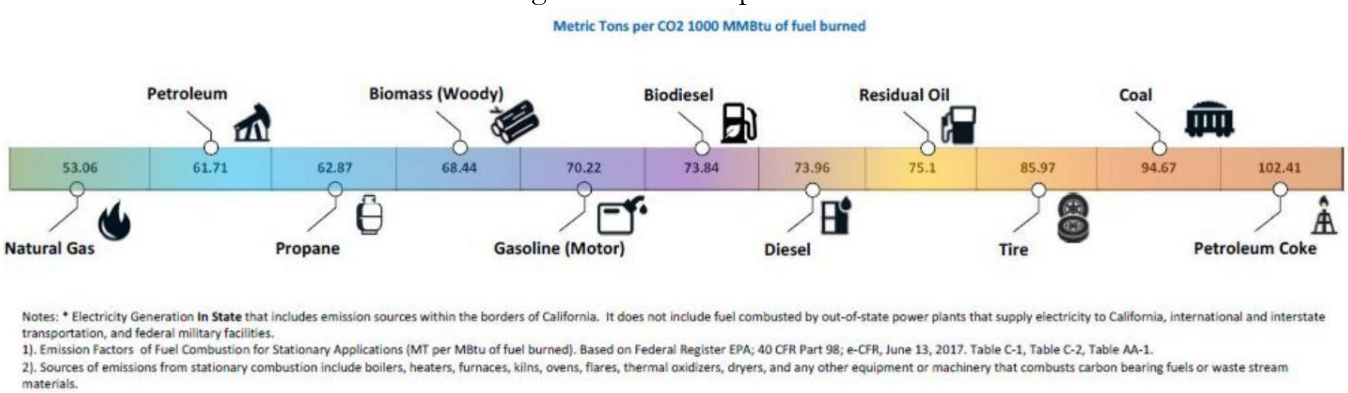
5.2.4 PG&E

Chris DiGiovanni—PG&E's Manager of Gas Strategy, Policy, and Development—focused his presentation on serving new industrial gas customers in difficult-to-electrify sectors. Mr. DiGiovanni recommended that the Commission allow new gas infrastructure—and continue allowances, discounts, and refunds for gas infrastructure—where gas is cleaner and/or cheaper than existing alternatives. He also suggested that the CPUC consider the utilities' legal requirements under the obligation to serve. Customers that may need gas in the future include electric generators; refineries; shipping; and industries with heavy-duty equipment such as those producing cement, concrete, chemicals, and glass. These industries are critical to support construction, economic development, and job growth.

Mr. DiGiovanni stated that there are several reasons various end-users may find it difficult to electrify. Some customers operate at high production rates or cannot sustain power loss. Many, such as cement producers, rely on chemical reactions that need combustion products and cannot use electricity as a substitute. He noted that there is a lack of available electric technologies that meet the needs of these customers. Mr. DiGiovanni suggested that, if gas infrastructure isn't available, it is likely that businesses with small margins will shut down or relocate out of state where requirements are not so stringent, resulting in job losses in California.

Mr. DiGiovanni asserted that the needs of new, hard-to-electrify industrial customers should be considered in gas system planning. He made several recommendations, including the following. Utilities should maintain infrastructure that serves current customers to allow for fuel switching from dirtier burning fuels. New infrastructure should be supported where it is beneficial to gas rates or provides environmental benefits. Incentives should be provided for hydrogen and renewable gas as well as fuel switching. Facilities construction that results in lower GHG emissions compared to the status quo should receive increased allowances and discounts. He provided an image of the carbon spectrum (see Figure 6) to illustrate that natural gas can provide carbon reductions compared to dirtier fuels.

Figure 6: Carbon Spectrum



5.2.5 Q&A, Panel 2

Commissioner Rechtschaffen asked Dr. Reed to respond to the concerns raised by Mr. Seever of Vista Metals raised, i.e., using hydrogen could impact product quality, increase NO_x pollution, and decrease productivity. Dr. Reed responded that their research suggests that burner design can create conditions in which hydrogen combustion has the same or lower NO_x as natural gas combustion. He said that his group hadn't looked into the issue of hydrogen's potential impact on product quality. In most cases, hydrogen or renewable gas would be used for high temperature process heat. There are a few processes where it would be a reactant, and those need to be specifically studied.

Commissioner Rechtschaffen asked Dr. Reed about his research into the substitutability of hydrogen or renewable gas for natural gas in high temperature heat applications. Dr. Reed responded that his group has studied a wide spectrum of appliances and some industrial burners and has found that many can accept hydrogen with no modification. As they test higher proportions of hydrogen, there may need to be changes in things like orifice diameter.

Commissioner Shiroma asked Mr. Seever how Vista Metals' discussions with SoCal Gas about using one of the company's furnaces to test the hydrogen blends were progressing and whether it was likely to happen. Mr. Seever responded that Vista Metals has held two separate conference calls with representatives from SoCal Gas and hosted several engineers who came on site and did a tour of the facilities. The primary concern is that, with the high real estate prices in California, there isn't enough space in their facilities. Having multiple truckloads of hydrogen in a fairly tight space could become a major safety concern. The engineers have not yet found a good way of addressing that issue, but Vista Metals is open to further discussion.

Commission Houck asked Dr. Reed to elaborate on his statement that there is value in deferring decisions on decommissioning until technological progress is clearer. She asked him to discuss the balance between making policy decisions that are going to help direct investment versus looking at the current status of technological progress given the time frames that the state has put forward on decarbonization. Dr. Reed responded that his group has been looking at a variety of different decarbonization strategies and plans, including studies from the United Kingdom and the Northeast. Looking at stock turnover rates and what's embodied in many of the plans in terms of how long it will take the electric technologies to diffuse, it doesn't seem necessary to make a firm decision on decommissioning the gas system for a number of years into the future. By that time, it will be clearer how things are tracking with respect to the Hydrogen Shot.[12] Broadly speaking, the gas system shouldn't be shut down until there's a reason to do so based on the progress of electrification.

Jonathan Bromson of the CPUC asked Mr. Smutny-Jones if he has an estimate of what the morning ramp increase in megawatts will be after decarbonization, noting that the winter morning gas ramp is much steeper than the evening ramp. Mr. Smutny-Jones responded that he doesn't have those numbers at hand. The key with the winter, he said, is that there is less solar energy produced throughout the day and that has been a significant issue. The winter ramp is largely being met with natural gas with the rest coming from imports, and this is something stakeholders need to pay attention to. Mr. Smutny-Jones said he hasn't done an internal analysis that compares the morning ramp to the evening ramp in winter, but the morning ramp seems to be predictable.

A question from the chat noted that SoCalGas has modeled future hourly gas needs for dispatchable electric generators to continue to support renewable deployment in conformance with Senate Bill 100 and other climate policies. That modeling shows that while annual throughput will be significantly reduced, peak hour gas use by electric generators will continue to grow, limited only by the capacity of gas-fired electric generators necessary to maintain reliability. The question asked was: Have any of the panelists undertaken any such modeling and what are your perspectives on the foregoing conclusion?

Dr. Reed responded that his group has done some modeling using both the Resolve model and another tool that has higher temporal resolution. That modeling shows that, dependent upon the price of the renewable fuel, it is significantly selected as a least cost resource beginning at a price of $24 per MMBtu and increases rapidly at the cost levels anticipated in the Hydrogen Shot, which is around $7-8 per MMBTU.

[12] The Hydrogen Shot is part of the Department of Energy's Earthshot Initiative. Launched on June 7, 2021, the Hydrogen Shot seeks to reduce the cost of clean hydrogen by 80 percent to $1 per kilogram by 2031 or roughly $7.40 per MMBtu: [Hydrogen Shot | Department of Energy]

Marcel Hawiger asked Mr. Seever whether Vista Metals is connected to a distribution or transmission pipeline and whether the company uses any special equipment to increase gas pressure. Mr. Seever responded that Vista Metals takes medium pressure gas off the local distribution company.

Michael Colvin of EDF asked Dr. Reed what investments to the gas system would be required for high blends of alternative fuels and whether UC Irvine has done a cost comparison of different required investments for renewable natural gas versus hydrogen versus other synthetic gases. Dr. Reed responded that the university has done quite a bit of comparative analysis regarding hydrogen versus methane, either the renewable forms or with carbon capture, utilization, and storage. Although the cost of converting to hydrogen is significant—in the billions—in general, hydrogen will be cheaper to make than renewable methane. His group's analysis does show that carbon capture, utilization, and storage would be potentially lower cost than hydrogen. However, it's uncertain whether California policy will permit the use of carbon capture, utilization, and storage.

Deborah Behles of CEJA asked Dr. Reed whether his group's least-cost analysis considered the social cost of carbon and the avoided air pollution cost. She also asked whether they had included the increased market, fuel, and maintenance costs of keeping gas plants online. Dr. Reed responded that the comparative analyses led to the same place in terms of in-state carbon emissions, so the social cost of carbon wouldn't show up in these analyses because there aren't differences in the carbon footprint. Generally, they include known and predictable costs of operation and maintenance of the system but not necessarily some of the indirect things that may be embodied in that question.

A question from the chat asked whether it would make sense to promote more flexible tariffs or rules to enable existing industrial load to connect directly to backbone service, thereby consolidating industrial service and enabling simplification of the pipeline system. Mr. DiGiovanni responded that the proximity of the industrial customer to the backbone system must be considered. He also noted that, "poking too many holes in the backbone could cause some safety issues." Mr. Seever agreed with Mr. DiGiovanni's response.

Mr. Smutny-Jones also addressed the question, stating that the sweet spot for building an independent power project 15 years ago was to be on a transmission pipeline underneath a transmission line. So, if there is a gas generation facility that is not on the backbone, that's probably an indication that retiring any gas line to them could impact local electric reliability.

5.3 Panel 3: Role of Storage

Scoping Memo Question g: What should be the role of existing natural gas storage facilities as a component of the gas utilities' infrastructure portfolio?

5.3.1 Rockpoint Gas Storage

Two representatives of Rockpoint Gas Storage (Rockpoint) spoke at the workshop, Jason Dubchak, (Vice President and General Counsel), and Toby McKenna (CEO). Rockpoint is the largest independent owner and operator of natural gas storage facilities in North America. It holds over 300 Bcf of working gas capacity in the United States and Canada. In California, it owns the Wild Goose (75 Bcf) and Lodi (31 Bcf) storage facilities.

Mr. Dubchak stated that natural gas storage facilities perform a number of important functions for maintaining a reliable and affordable gas supply, including: 1) capitalizing on the seasonal, monthly, and daily imbalance between supply and demand for natural gas; 2) providing customers with the ability to store natural gas for use or resale in a higher value period; 3) providing a place to inject excess summer supply and to withdraw gas need to meet peak winter demand; 4) allowing customers to match largely constant supply with variable demand; and 5) providing a reliable and safe physical backstop during energy grid operational issues.

Mr. McKenna noted that storage helps California customers manage competition with other markets. California storage draws don't completely correlate with in-state weather. Cold weather elsewhere can cause California customers to have to compete for gas flows with customers in other states. Storage provides an alternative to interstate gas supplies when markets are tight.

Mr. McKenna stressed that Rockpoint is an "embracer" of the natural gas transition. He stated that the company can be a major player in the transition, blending RNG and responsibly sourced gas and ultimately hydrogen. Rockpoint is currently working with small groups of wood waste harvesters and providing trucking to take these small producers' output in sufficient volumes to make it economically viable. The company is also conducting hydrogen blending projects in California and Canada to determine how much hydrogen can be blended in sub-surface applications. He maintained that Rockpoint is developing an emerging marketplace that enhances price transparency, liquidity, and capital backstopping for renewables and carbon credit development.

5.3.2 Southern California Edison

Marci Palmstrom, the Director of Trading and Operations at Southern California Edison (SCE), stated that gas storage plays an important role in maintaining reliability and managing operational flexibility. When available, it is a "tool in the toolbox" that helps customers balance when they are over- or under-supplied. She noted that SCE has not had access to storage in recent years but that the company did use it when it was available.

As the state moves toward meeting its clean energy goals, SCE expects gas usage and gas-fired generation to decline, thus reducing, but not eliminating, reliance on gas storage for balancing. Ms. Palmstrom pointed to new renewables plus battery storage that are expected to come on-line by 2026 in light of the CPUC's Mid-term Reliability Procurement requirements. She expects the new batteries to help with the summer ramp but expressed some uncertainty about how reductions in gas would affect winter electric reliability. She stated that additional studies are needed to determine whether a sizeable reduction in gas storage capacity would impact electric system reliability in winter or summer months in the near term (e.g., thru 2026) as well as in the long term (e.g., 2027-2045).

5.3.3 California Center for Science and Technology

Dr. Jane Long previously served as the Co-Chair of the 2018 California Center for Science and Technology (CCST) study of the Long-Term Viability of Underground Natural Gas Storage in California and is now with the Environmental Defense Fund (EDF). Her presentation primarily focused on her work on the CCST study but also touched on a study she is currently working on, "SB 100: Pathways to Success."

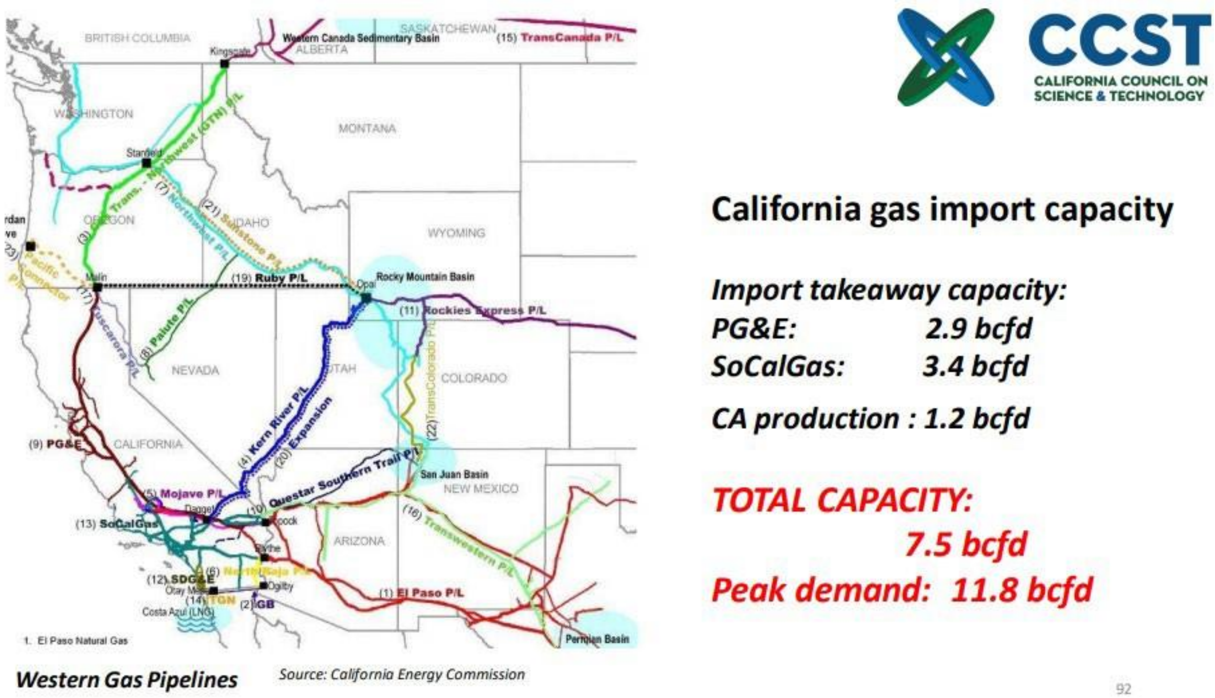
The CCST study was commissioned by the California Legislature following the 2015 Aliso Canyon rupture. It was designed to answer three key questions:

1. What risks do California's underground gas storage facilities pose to health, safety, environment, and infrastructure?
2. Does California need underground gas storage to provide for energy reliability in the near term (through 2020)?
3. How will implementation of California's climate policies change the need for underground storage in the future?

With respect to question 1, Dr. Long stated that new CalGEM[13] regulations requiring tubing and packer construction of well casings greatly reduce the likelihood of loss of well containment. She also noted that not all wells are equal; they have different risk profiles and different levels of usefulness. The CCST study's key additional takeaways with regard to question 1 were that regulations should continue to be reviewed and improved, each site should be monitored for leaks and prepared for rapid modeling of gas dispersion, and each site should be evaluated based on its risks and benefits.

Dr. Long used the following slide to make the point that California is at the end of the North American pipeline system, and there is a significant gap between the state's winter peak demand of nearly 12 billion cubic feet per day (Bcfd) and its import takeaway capacity of 7.5 Bcfd.

Figure 7: California Gas Import Capacity



One of the primary functions of gas storage is to meet winter demand when it exceeds the available pipeline supply capacity. Without storage, California would be unable to consistently meet winter demand. Dr. Long asserted that if there is sufficient storage to meet winter demand, then there is enough capacity to fulfill the other functions of storage. These include intraday balancing, including backing up renewable energy; compensating for differences between variable demand and steady production; creating an in-state stockpile for emergencies; and allowing for arbitrage and market liquidity.

Dr. Long reported on CCST's findings with regard to question 2, which focused on the need for storage through 2020. She noted that winter peak gas use is driven by heating demand, not electricity, and there was no method of conserving or supplying electricity that could have replaced gas storage by 2020.

She described alternatives to storage that were examined in the CCST report. Building more gas transmission pipelines would cost approximately $15 billion[14] and would shift the risk of supply not meeting demand upstream, meaning that California's supply could be reduced by cold weather out-of-state that

[13] The California Geologic Energy Management Division (CalGEM) was previously known as the California Division of Oil, Gas, and Geothermal Resources or DOGGR. Dr. Long's slides refer to the division by its previous name.
[14] All cost estimates in this paragraph are in 2018 dollars.

affects the entire region. Liquified natural gas (LNG) peak shaving units would cost about $10 billion, would be difficult to permit, and would present other risks and challenges. Similarly, containerized LNG units might help support peak load for a few hours but do not seem to be viable at the scale needed to close the peak day gap. Dr. Long stated that 2,000 such containers would be required to support a 50 MW power plant for four hours, and the transportation of the containers would also raise safety and emissions concerns. Shifting generation out-of-area would not solve the problem of serving winter heating load. Shaped nominations and flexible services could reduce the peak. A weekend natural gas market might help but would need agreement.[15] Dr. Long stated that the supply-demand problem would be exacerbated by electrified heat because heating needs peak in winter when solar and wind outputs are minimal. She maintained that the required gas backup is equal to renewable energy capacity. In short, "there is no 'silver bullet' to replace underground storage."

Dr. Long then turned to discuss the "SB100: Pathways to Success" study she is currently working on, which looks at various scenarios for meeting California's SB 100 goals.[16] As shown in Table 2 below, the study finds that without clean firm power, meeting California's goals requires 6,250 square miles of land and causes electricity costs to climb substantially from around 9 cents per kilowatt hour (kWh) to 15 cents/kWh. She added that the amount of solar the state can add will likely be limited by land use and transmission requirements rather than cost.

Table 2: Meeting California's SB 100 Goals with and without Clean Firm Power

Issue		With Clean Firm Power	Without Clean Firm Power
Costs for generation and transmission *California transmission and distribution costs are currently about 9 cents/kWh*		~9 cents/kWh	~15 cents /kWh
Solar and Wind Capacity *Entire U.S. electric generating capacity is ~1100 GW*		25 – 200 GW	470 GW
New Storage* *Largest battery facility now being built is 0.3 GW /1.2 GWh. CA expects to have 2 GW battery capacity in 2021*	**New short-term battery capacity**	20 -100 GW	160 GW
	New Energy storage	100-800 GWh	1000 GWh
Land Use *CA land area is ~164,000 sq miles*		625- 2500 sq miles	6250 sq miles
Transmission *CA currently has ~ 15 million MW-miles of transmission*		2 – 3 million MW-Miles	~9 million MW Miles

**Energy storage beyond existing pumped hydro*

[15] The Federal Energy Regulatory Commission (FERC) regulates interstate gas transportation, including rate-setting and scheduling practices. Thus, gas market rules are determined at the national level, and parties are free to advocate in that forum for changes to the rules. For example, in March 2014, the FERC issued a Notice of Proposed Rulemaking, RM 14-2-000, to better align gas and electric markets that proposed changes to nationwide gas scheduling practices. FERC gave stakeholders six months to reach consensus using the North American Energy Standards Board [NAESB] process. The rulemaking changed the nomination deadline for the interstate Timely Nomination Cycle and created an additional cycle in the gas day in Order 809 151 FERC ¶ 61,049 (2015): FERC Approves Final Rule to Improve Gas-Electric Coordination | Federal Energy Regulatory Commission.

[16] SB100: Pathways to Success: www.edf.org\cleanfirmpower.

In conclusion, Dr. Long said that with proper regulation and monitoring, underground gas storage can be safe, and it is highly likely that California will need it in the coming decades. However, she noted that the state may not need all currently existing gas storage facilities; some are riskier than others, and some are more useful than others. In the future, such storage facilities may be used for hydrogen, biofuels, or captured carbon. Lastly, she stressed that California needs an integrated, decarbonized energy plan that covers both capacity and reliability over all seasons and for all sectors: electricity, heat, and transportation.

5.3.4 Cal Advocates

Mark Pocta, a Program Manager for Cal Advocates,[17] stated that he expects there to be a continuing role for natural gas storage facilities as a component of the gas system for the short and mid-term, meaning the next 10 to 15 years. Over that period, Cal Advocates expects that storage will continue to provide seasonal reliability to the market through inventory withdrawal capacity used to serve the system's peak load, particularly on cold days in winter. He also stated that gas storage provides benefits to the gas and electric markets in general.

PG&E meets its cold day peak day requirements by relying on firm interstate capacity rights, withdrawal rights from its own utility-owned storage, and contracts with independent storage providers held on behalf of core customers. Several years ago, Mr. Pocta noted, PG&E requested authorization to close its Los Medanos storage facility. At that time, Cal Advocates proposed that PG&E continue to operate the facility because it provides added resiliency to the system. The position taken by Cal Advocates in that proceeding indicates that it has generally recognized the resiliency that gas storage provides in California. Mr. Pocta agreed with Dr. Long's remark that California is located at the end of interstate pipeline systems that serve not only California but upstream markets. On peak days, there is demand from those upstream customers. While that typically isn't an issue, it could be, in times of very cold weather. Having gas storage in-state helps to assure reliability.

Mr. Pocta added that during periods of cold weather, there are also impacts to the production wells in some of the gas supply regions, and those can impact deliveries into the California market. He stated that gas storage will remain a very important component fof California's infrastructure, ensuring that the gas demands of core customers and other customers are met during these high demand times.

In the longer term, as gas demand patterns in California evolve, various parties will need to consider how storage can be optimized in conjunction with the use of interstate capacity. There might be other policy and safety considerations regarding storage that various parties will want to take into account over that longer term horizon.

5.3.5 Summary of Q&A

Commissioner Rechtschaffen asked Dr. Long to elaborate on the likely need for gas storage for alternatives like hydrogen, biofuels, or carbon dioxide as California deeply decarbonizes its energy system. He noted that Dr. Reed had said earlier that it might make sense to keep things in place for now to see how technologies develop. However, there is a large cost to that because maintaining the safety and reliability of existing infrastructure is not free, and the state is trying to do a great number of things all at once. The Commissioner further asked Dr. Long to comment on what a least-regrets policy might be.

Dr. Long responded that California needs an integrated plan, substantiated with analysis, on the time and seasonality of gas use, noting that this analysis is difficult to do because a lot of the data on the gas side is proprietary. She maintained that if California wants to decarbonize, the state needs 30 gigawatts of clean

[17] Mark Pocta's presentation did not include any slides.

firm power by 2045 and that this should be the starting point in determining the state's strategy. She added that she would prefer to keep Diablo Canyon open and have some nuclear power available. Another good bet is carbon capture and storage (CCS) because existing storage facilities could be repurposed to store carbon dioxide. The state already has a lot of gas infrastructure that ratepayers have spent a lot of money on. She recommended keeping that infrastructure for a time and then figuring out where 30 gigawatts of CCS could best be stored.

Backing up, California needs to decide what kind of clean firm power it really wants, Dr. Long stated. That will have the biggest impact on how much storage is needed and what kind of storage and where and when.

Commissioner Rechtschaffen responded that the state is still trying to figure it out. There have been enormously promising developments in clean firm power just in the past year or two that are nongaseous, but it is unclear how quickly they will be deployed or how expensive they will be. The CPUC is considering these issues in its Integrated Resource Planning proceeding, which is electricity focused. The agency is very much aware that a more holistic, cross-sectoral planning process is needed. This gas proceeding is one part of that effort.

Dr. Long asked whether the advances the Commissioner referred to include long-term energy storage. Commissioner Rechtschaffen said they did.

Dr. Long replied that long-term energy storage isn't clean firm power because it still runs out. So it is unlikely to help solve a seasonal problem. She maintained that the state has to "face the music on clean firm power," unless there is enough energy to supply the long-duration storage.

Commissioner Houck responded that this discussion underscores the importance of this proceeding and coming up with a plan.

A question from the chat asked whether the models in Dr. Long's presentation also considered the production of rooftop solar potentially paired with consumer batteries. Dr. Long replied that they did.

Michael Colvin of EDF asked the panelists whether gas storage facilities provide significant economic benefits to ratepayers. He noted that storage acts as a hedge against volatile pricing but asked whether that creates a uniform economic benefit across customer classes or if it is concentrated on a particular subset of gas customers. If the benefit is concentrated, can that bill relief be replicated through other programs i.e., changes to CARE, time-of-use rates etc.?

Mark Pocta responded that storage costs are allocated among the customers in cost allocation proceedings. Core customers—the residential and commercial customers—are allocated a certain amount of rights to store gas capacity to meet their needs. If the utilities are able to optimize their storage holdings—and this is seen more in the case of SoCalGas—they are able to sell those rights on the secondary market. The benefits from those sales flow through back to core customers as a credit to their gas costs. He added that he didn't currently have any thoughts on whether that strategy could be applied to other programs.

Michael Colvin responded that a lot of the panel's presentations focused on the technical benefits of gas storage facilities and how it is needed for the system, but he was interested in how the economic benefits of having that natural hedge get allocated among core customers. There are some customers who will experience a larger benefit than others. For example, a five-dollar benefit to a low-income customer is likely to be very different than the benefit to a large commercial customer. From a planning perspective, if gas storage fields are not going to be used as much, there needs to be a way to replicate its economic benefits. He maintained that the cost allocation methodology doesn't fully capture that.

Mr. Pocta replied that Mr. Colvin was correct. Costs are currently allocated on a class basis; they aren't broken down beyond that, especially with storage.

Matthewson Epuna of SED asked Dr Long to talk more about an integrated approach to decarbonization. Dr. Long responded that a lot of things are interacting. For example, in California, heating demand has been largely taken care of with direct use of gas. Many models have said that to get all the way to meeting California's goals, heat has to be electrified. However, at the same time, the state wants to increase the amount of renewable energy that is used. The problem is that the demand for heat is anti-correlated with the availability of renewable energy. In addition, the state is electrifying transportation. Transportation used to be completely separate from electricity. So all of the ways in which these systems interact—in terms of how much of a resource is needed and when it is needed and how the sources of energy are going to shift to meet all of the state's needs—have to be looked at in an integrated fashion. The question is whether to plan that or to allow it to emerge. Dr. Long stated that she would be reluctant to allow it to just emerge because then policies could be put in place that don't optimize the system as a whole. For example, if the policy is to maximize solar energy and disallow the use of gas in buildings, there will be a problem in the winter. Some kind of integration across all the sectors—even if it was at a very gross level—is important before polices are put in place for any one sector.

Jason Dubchak of Rockpoint addressed Mr. Colvin's earlier question on how storage benefits core customers by pointing out that core customers are benefiting from the storage strategy that was approved in PG&E's last rate case. There is a demarcation between facilities that were built many years ago and changed into natural gas storage facilities versus facilities like Rockpoint's that were purpose-built for natural gas storage. The costs that are going to be passed on to ratepayers to bring old facilities up to the new specifications and regulations are going to be a lot different than those for a facility that was purpose-built 10-15 years ago.

Paul Chernick asked Dr. Long, "Aren't heat pumps efficient enough that the amount of gas used for heating will be lower with a heat pump than from direct gas use in a furnace?" Dr. Long responded that the amount of energy used for a heat pump will certainly be lower. The question lies with the fuel source for the electricity generated to serve the heat pump. That should be part of the integrated plan. It would quantify how much electricity is needed for heating in the winter and then verify whether enough electricity is available for both the electrification of heating and transportation.

Christian Lambert of Cal Advocates directed a question to Marci Palmstrom, noting that SCE expects reduced gas usage and less reliance on gas generation, thus reducing reliance on gas storage for balancing. He asked Ms. Palmstrom for Edison's response to other panelists' arguments and modeling results that indicate that future electric ramping, peaking, and firming needs will lead to an ongoing need for underground gas storage. Ms. Palmstrom responded that SCE's modeling shows natural gas consumption declining by 2045 compared to today. However, she agreed that there will be an increase in ramps by 2030. The solar that is coming online in the middle of the day depresses the need for electricity, so once it goes away at the end of the day, there is some ramping. She stated that SCE's modeling accounts for energy storage to help offset that peaking demand as opposed to any new gas-fired resources.

5.4 Panel 4: Interpreting the Obligation to Serve

Scoping Memo Question h: How should the monopoly local distribution companies' "obligation to serve all customers who want service" (see D.15-10-050, at 18) be defined, given the state's decarbonization goals? What statutory and policy changes, if any, are needed to effectuate such a definition?

5.4.1 CPUC Legal Division

Jonathan Bromson of the CPUC's Legal Division moderated Panel 4 and began by reviewing the sections of the California Public Utilities (PU) Code that touch on the obligation to serve including §§ 221, 222, and 216 (a)-(b). Mr. Bromson stated that the traditional interpretation is that the gas utility must provide gas service to customers who request it. He noted that there is some nuance in the code regarding whether the obligation to serve ends when the customer leaves gas service.

5.4.2 Stanford Law School

Dr. Michael Wara,[18] a Senior Research Scholar and Director of the Climate and Energy Program at Stanford Law School, discussed the findings of a paper he recently co-authored.[19] The paper considered whether the CPUC has the legal authority to allow or mandate the substitution of electric service for natural gas service and identified two main legal issues. The first legal issue is whether there is a substantive obligation to provide a particular kind of service and whether the Commission would be given the broad discretion to take the step of finding an equivalence between different types of energy sources delivered to a residential customer. Dr. Wara stated that it's crucial to have enough clarity in the statute to create the certainty necessary for utilities to make investment decisions to meet decarbonization goals. He added that various pieces of analysis presented by the California Energy Commission, E3, and his group, shows that the "branch pruning strategy" is likely the most cost effective and equitable way for gas-to-electric transformation.

Dr. Wara provided historic examples in which major substitutions of regulated services were authorized in California including the switch from manufactured gas to natural gas in the late 20th century, the switch from 50 hertz to 60 hertz service in Southern California Edison's service territory in 1948, and the transition from ferry to bus service. In the latter case, the Commission found that the substituting bus service for the discontinued ferry service was a reasonable and adequate substitute. Courts weigh several key factors in evaluating substitution-of-service cases, including convenience, number of customers affected, and the impacts on low-income customers.

The second legal issue is that of fundamental due process, which he believes would apply to any kind of cessation or material alteration of gas utility service. After looking into the California and national precedent, his understanding is that the interpretation of the obligation to serve has been by utility and by energy source. Utility service is covered by a line of cases that provide due process protections similar to government-provided benefits. Secession of service therefore requires notification of customers and the opportunity for customers to be heard regarding the change. Dr. Wara referred to the San Joaquin Valley energy pilots as an example of transition planning at the community level.

Dr. Wara discussed the issue of dual-fuel versus single-fuel utilities. For PG&E, the substitution of electric service for gas service would be managed by the same firm. For SoCalGas, Edison, and the Los Angeles

[18] Dr. Wara's presentation did not include any slides.

[19] The co-authors of "Removing Legal Barriers to Building Electrification" include Amanda Zerby of New York University; Nick Wallace, a recent graduate of the Environmental M.S. program at Stanford Law School; and Debbie Sivas, the director of Stanford Law's Environmental Law Clinic: Removing Legal Barriers to Building Electrification - Report - Stanford Law School.

Department of Water and Power, the issue is not just substitution of different forms of service by one firm but also substitution from service by one firm to service by another. This, according to Dr. Wara, significantly complicates the legal analysis.

To conclude, Dr. Wara stated that the Commission arguably has the authority to mandate substitution of service. However, it would be valuable to have legislative clarification because it would create greater investment certainty for the investor-owned utilities to build and maintain their networks.

5.4.3 California Environmental Justice Alliance

Deborah Behles, an attorney representing the California Environmental Justice Alliance (CEJA), suggested that stakeholders should first recognize the importance of the duty to serve and its intention of ensuring that all customers have access to necessary utility services. She noted that there have often been racial disparities in the provision of utility service. She then referenced Section 451 of the Public Utilities Code, which requires that utilities furnish and maintain adequate, efficient, just, and reasonable service. Ms. Behles stated that she was making the assumption that the Commission has the authority to manage the transition, thus her presentation would address the considerations that would ensure that substitution of service meets the need to be just.

Ms. Behles stated that a managed transition is needed to ensure that electrification does not benefit only wealthier households. When determining the parameters of a just substitution, she maintained that it is important to consider the barriers to electrification that low-income and disadvantaged community households face. Structural barriers include low ownership rates, insufficient access to capital, building age, and location in remote or underserved communities. Among the policy barriers such households face are market delivery, program integration, and data limitations. Other barriers include a higher energy burden, disconnections, and access to services and technologies. She suggested that the San Joaquin Valley project provides an initial framework for examining the types of considerations that should be included.

Ms. Behles outlined the following core considerations.

1. Community input and outreach should include education on the benefits of electrification in an understandable and accessible way to ensure community-driven local benefits. Outreach should include authentic partnerships with trusted, community-based organizations that can be partnered with to inform meaningful community engagements.
2. Include local electrical grid resiliency in the outreach process by considering options such as local clean microgrids.
3. Assistance with capital investments, especially for low-income households, is necessary to achieve an affordable substitution. Assistance programs, such as the Energy Savings Assistance Program (ESA), should look into energy efficiency measures.
4. Bill protection is important to low-income and disadvantaged communities, as rates are increasing due to wildfires and other costs. High energy bills can also be a health issue, as they may cause low-income households to make insufficient use of heating and cooling.
5. Tenants should be protected from rent increases and eviction for a period of time after the installation of new electrical appliances.

5.4.4 New York University School of Law

Justin Gundlach, a senior attorney at the Institute for Policy Integrity at New York University School of Law, noted that up until 2010, gas was looked upon as a better fuel than the alternative—fuel oil. Factors such as Super Storm Sandy, drilling in the Marcellus Shale, and the Paris Climate Agreement pushed New York away from gas. In 2019, the state passed the Climate Leadership and Community Protection Act, which commits to reducing emissions 40 percent below 1990 levels by 2030[20] and 85 percent below 1990 levels by 2050.

Mr. Gundlach noted that the obligation that utility law places on gas utilities to serve customers is in sharp tension with New York's climate law, adding that the New York Public Services Commission has a similarly ambiguous ability to change the utilities' obligation to serve as its counterpart in California. He suggested that a legal argument could be made that the new climate law implies the repeal of the older utilities law. That argument might succeed, but it would be a rocky and uncertain path, and the New York Commission has signaled an unwillingness to act without legislative direction. Mr. Gundlach agreed that legislative changes are preferable because they would provide a more solid foundation for the transition away from gas than regulation could.

New York's utility law declares that the provision of gas service, as well as electricity and steam service, is in the public interest. It also directs utilities to provide service to residential and commercial customers who request it. Mr. Gundlach noted that changes made to this area of law over the past 40 years were not the result of regulatory capture but reflect concerns about consumer protection and local air pollution.

Mr. Gundlach stated that New York's Climate Leadership and Community Protection Act is still a work in progress, and detailed emissions reduction regulations won't be issued until 2024. He added that the economy-wide emissions reductions it requires are not sector-specific and that agencies must consider whether their actions align with overarching emissions targets and justify those that don't.

According to Mr. Gundlach, there are several New York Commission actions that indicate legislative change is needed, including: 1) the gas planning proceeding does not impose a stringent emissions neutrality condition for non-emergency projects and aims to avert moratoria on new gas hookups; and 2) in reference to a rate case settled in fall of 2021, the New York Commission stated that the Climate Action Council has yet to provide guidance on how to resolve the tension between the emissions reductions mandated in the new climate law and the obligation to serve.

Mr. Gundlach provided a list of suggested legislative changes in New York's utility law: 1) clarify that where the climate law and utility law are in tension, the climate law prevails; 2) delete "gas" from the list of resources provided "in the public interest"; 3) cease facilitating fuel switching to gas; 4) eliminate all express or implied presumptions of permanence for gas service; and 5) eliminate the obligation to restore suspended gas service. He noted that such changes will undermine the current business model for gas utilities and create problems for people who find it hard to electrify.

5.4.5 Berkeley Law

Ethan Elkind and Ted Lamm—both of the Center for Law, Energy, and the Environment (CLEE) at Berkeley Law—gave a joint presentation. Mr. Elkind introduced a January 2021 policy report that CLEE worked on, "Building Toward Decarbonization,"[21] which recommended prioritizing the electrification of lower-income and disadvantaged communities, areas affected by wildfires, new construction, and areas with old infrastructure. According to the report, two barriers to reaching near-term electrification goals are the lack of consistent state policy and stakeholder limitations. The report suggests that leadership in the form of executive orders and legislative timelines as well as clarification of the obligation to serve would help create a long-term path for the complete decarbonization of buildings.

[20] Mr. Gundlach's slide stated that New York's emissions goal is "30 x 2040." Other sources say the goal is to reduce economy-wide emissions 40 percent by 2030: New York's Climate Leadership and Community Protection Act (CLCPA) (ny.gov).
[21] Building Toward Decarbonization: Building-toward-Decarbonization-January-2021.pdf (berkeley.edu).

Mr. Lamm noted that although Public Utilities Code 451 established the general obligation to serve, it's not well-defined in statute and needs legislative clarification. PU Code 328 and PU Code 328.2 established a specific gas obligation to serve and should be acknowledged by the Commission before changes are considered at the legislative or policy level.

In response to Scoping Memo question h, Mr. Lamm stated that legislation to amend the PU Code would help resolve this issue. Specifically, the Code should clarify that the utilities' obligation to serve relates to energy services such as heat, light, and power and not to natural gas or other fuel. They noted that from an equity, social, and legal perspective, it's vital that any transition program that modifies the obligation to serve consider the affordability and usability of the substitute service. Mr. Lamm concluded the presentation by noting that reliability of service could be an issue under PU Code 451, especially in areas with significant differentials between gas and electric reliability during certain periods of the year.

5.4.6 Summary of Q&A

Commissioner Rechtschaffen asked Michael Wara to elaborate on why switching service within an area where a customer gets their electricity service from one provider and gas service from a different provider would prove to be legally challenging. Mr. Wara explained that there isn't much case law involving the transfer of obligation to serve from one regulated utility to another. He also clarified that, although the transfer is potentially manageable, it can create risk that could be a barrier to larger scale implementation until it's resolved. Mr. Wara added that the concern for some utilities involves customers who enter an area after electrification has occurred or change their minds about electrification.

Commissioner Rechtschaffen then asked Justin Gundlach if his research extends beyond New York. Mr. Gundlach stated that his research examined whether one could read implied repeal into other states' climate provisions and found that the answer was largely consistent across the board. The consequences of attempting to update or undo the obligation to serve does not solve the problem of a systemwide transition.

President Reynolds asked Deborah Behles to expand on the bill protections she mentioned for low-income and disadvantaged communities and whether there are additional mechanisms that would help achieve that goal. Ms. Behles explained that CEJA has been examining the possibility of moving to a percentage of income payment plan, which some states have already adopted, to ensure that households are only paying a certain percentage of their income for energy costs. She added that community input is important to this process.

Commissioner Houck prompted a discussion on how reach codes and local ordinances play into the requirement to serve since an increasing number of local jurisdictions are requiring electrification. Ted Lamm stated that, while reach codes are an important first step in building electrification, they're not likely to drive much change in the short run since few houses are being built in California. He added that there is an active discussion of banning the sale of new gas appliances, which would drive more change because it would affect both new and existing housing stock. Mr. Gundlach stated that in New York's experience, the reach codes themselves are not going to drive much change. Other sources of pressure or guarantees that the end is foreseeable are necessary.

Commissioner Houck then directed a question to Ms. Behles on how to expand programs that assist low-income and disadvantaged communities to electrify so that they are not left behind. She also asked Ms. Behles to elaborate on ideas for encouraging landlords to support these types of projects. Ms. Behles reemphasized that community outreach through a trusted community-based organization is crucial.

Regarding additional ideas, Ms. Behles mentioned a "one-stop shop" that combines weatherization, energy savings assistance, and technology programs, all of which help overcome barriers beyond just capital costs.

In the chat, a question to Mr. Gundlach read "If the obligation to serve is different for a new customer requesting a hookup, customer protection for those who were historically redlined against service versus an existing customer who may be able to have a fuel substitution but still be served?" Mr. Gundlach stated that there are two different provisions: Public Service Law Section 31, which pertains to new requests and Section 66b, which contains language on continuation of service and leaves less room for substitution. Mr. Wara added that it should not be different under the law, as it currently exists, but whether equity would favor treating those customers differently is a separate issue.

As a follow-up question, Jonathan Bromson asked Mr. Wara if the Commission could mandate electrification if existing customers are not equipped to switch to all-electric service due to affordability issues. In response, Mr. Wara stated that if a program doesn't have equity requirements, the court would be less sympathetic to substitution. He added that it is important to consider how customers who hold-out on electrification will be treated. If there are one or two such customers, the situation might be similar to the ferry example where most people had already switched to buses, so the court was more sympathetic to allowing the substitution. People also need time and warning before any changes to service are initiated. Mr. Lamm added that substitute service has to be available.

In response to a question on whether the five-year eviction ban mentioned by Ms. Behles had an effect on the number of landlords willing to participate in the San Joaquin Valley Pilot, Abigail Solis wrote in the chat, "This agreement had very low impact on the number of landlords that participated. We faced some barriers with larger property management companies. Luckily, in the San Joaquin Valley, most landlords are local and do not use property management companies."

5.5 Panel 5: Milestones for Derating and Decommissioning

Scoping Memo Question i: Should the Commission require the achievement of certain milestones (e.g., replacement energy resources are built and operational) before a significant natural gas asset is derated or decommissioned to ensure energy reliability, equity, workforce planning, and other policy goals are maintained and/or achieved throughout this transition?

5.5.1 CAISO

Delphine Hou,[22] the Director of Regulatory Affairs at the California Independent System Operator (CAISO), began by noting that her comments would also touch on Scoping Memo question e, which discusses the sufficiency of local electric capacity to reliably serve customers that move off gas systems, as well as question f, which discusses the infrastructure needs for electric generators. She stated that CAISO believes that replacement energy should be either built and operational or well underway before a significant natural gas asset is derated or decommissioned to ensure reliability. Ms. Hou added that this also assumes that sufficient modeling and planning has already been conducted and that the appropriate replacement energy has been identified. As an example, she described the relationship CAISO has with the Commission. The IRP process provides a generation portfolio at least 10 years out to the CAISO's transmission planning process. CAISO's detailed local capacity studies can also provide estimates of battery storage and an analysis of charging limitations on battery storage.

[22] Delphine Hou's presentation did not include any slides.

Ms. Hou provided insight into CAISO's study on transmission options, which helps identify constraints on the system and how to reduce them. For CAISO's analyses to be more accurate and lead to actionable plans, CAISO would need detailed generation information to model, which includes the replacement energy resources. She noted that the modeling process would be iterative. With uncertainties such as multiple cloudy days that reduce renewable generation and/or battery storage, CAISO strongly recommends that detailed modeling is first based on scenarios that the Commission supports or the state supports, for example through its SB 100 process.

5.5.2 Southern California Edison

Marci Palmstrom is the Director of Trading and Market Operations at Southern California Edison. Ms. Palmstrom cautioned that it may be too early to adopt specific milestones and that doing so may create more hurdles to progress in the long run. She stated that it's important to have a long-term, transparent process that will allow vetting with stakeholders. Assets will differ in terms of safety and affordability. SCE's recommended holistic approach includes: 1) alignment with the Commission's reliability requirements and consideration of the development risk of expected new electric generation; 2) alignment with statewide milestones and policy initiatives such as the CEC's Integrated Energy Policy Report (IEPR), building electrification, EV sales; 3) coordination with CAISO local reliability needs to ensure grid stability; and 4) more comprehensive understanding of winter reliability needs. She stated that SCE is committed to helping California reach its long-term decarbonization and GHG reduction goals, which will require a significant reduction in gas usage in all sectors and a sizeable increase in transportation and building electrification.

5.5.3 Summary of Q&A

The following question was directed to Delphine Hou in the chat: "Since batteries have a finite number of charge or discharge cycles available, does this suggest that California should be looking at storage facilities that don't have these limitations, such as pumped hydro, pressurized air storage, or other gravity-based systems?" Ms. Hou responded that, since battery storage is relatively new, CAISO is still trying to understand its operational characteristics, such as lifespan and replacement provisions. These characteristics are put into CAISO's models, which select from an optimized portfolio in conjunction with the CEC's demand forecast to get a fuller picture.

5.6 Panel 6: Streamlined Approval of Zonal Electrification

Scoping Memo Question k: Should the Commission establish a mechanism for streamlined approval of cost-effective, time-sensitive zonal electrification? If so, what should this mechanism be?

5.6.1 PG&E

David Sawaya, Senior Manager of Decarbonization Strategies at PG&E, affirmed that the utility is in favor of a streamlined approval process for zonal electrification. He described four, small-scale zonal electrification projects that PG&E has completed, offsetting approximately $4 million in planned gas project costs with $400,000 in electrification investments. The company can identify high-potential zonal electrification candidates using a range of data related to the gas system, customer propensity, policy, and other factors. Mr. Sawaya noted that no single piece of data is sufficient to identify promising candidates and that, in all cases, locations need to be validated by detailed engineering review. Mr. Sawaya maintained that a streamlined approval process for these projects along with modified accounting treatment would provide access to larger capital and expense budgets that would allow PG&E to conduct more projects at larger scale.

Mr. Sawaya recommended that a zonal electrification process be streamlined and replicable, informed by clear guidance on what is considered cost-effective, and supported by equitable cost recovery. Streamlining is necessary to align with scoping, design, and execution timelines, especially when projects are being undertaken for risk mitigation. Among his suggestions for streamlining approvals were expedited proceedings that must be completed in 12 months such that the gas project would goes forward failing Commission action within this timeframe. For less complex projects, Tier 2 or 3 preformatted advice letters may be used to seek approval. With regard to cost-effectiveness, PG&E currently considers a metric of net present value, comparing the cost of the required gas work to the cost of electrification. Mr. Sawaya suggested that the Commission consider including external benefits, such as GHG reductions, to the cost-effectiveness formula as well as leveraging external funding to help with near-term opportunities. For equitable cost recovery, the Commission should consider how costs are recovered, e.g., whether capital expenditures approved for a gas pipeline can be repurposed toward electrification expense costs. The CPUC should also decide who costs will be recovered from: gas or electric ratepayers. Lastly, the Commission should consider if cost recovery will differ for projects spanning multiple GRCs or joint utility jurisdictions and areas with community choice aggregators (CCAs).

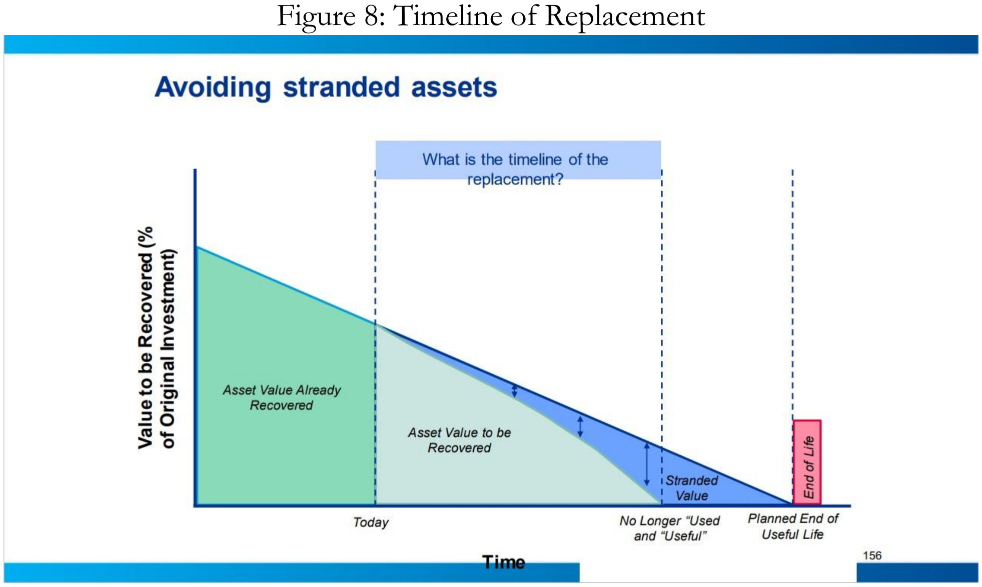
5.6.2 Environmental Defense Fund

Michael Colvin, Director of the California Energy Program at the Environmental Defense Fund, stated that upfront guidance from the Commission is critical to allow the possibility for utilities to take expedited action on zonal electrification. He explained that targeted electrification can allow for the decommissioning of a gas asset. The utility would need to demonstrate how this electrification would occur, and Mr. Colvin expressed doubts about this being done through an advice letter process, particularly in Southern California, which is largely served by single-fuel utilities. He suggested that there might be a dollar value cut off for using the advice letter process versus an application. Marketing, education, and outreach would be an important part of the application process. Mr. Colvin also noted that the utility should focus on different building stocks and ownership models.

Mr. Colvin posed the question, "How do we know that the utility has targeted electrification in the right way?" He suggested that the embedded book value or related values is a key criterion. He added that beyond cost-effectiveness, zonal electrification can be a key strategy to manage stranded costs.

Mr. Colvin presented Figure 8 below and suggested that the Commission should avoid stranded asset risk. To do so, the Commission must determine the timeline of the replacement project. Typically, this timeline would be driven by the GRC cycle, but there could be other timelines worth considering.

Figure 8: Timeline of Replacement



Mr. Colvin concluded with key elements for the application. The utility should specify within the application: 1) the number of CARE customers to be treated; 2) the number of customers located in a DAC; 3) the estimate book value of retired assets; 4) an estimate of average customer savings on energy burden; and 5) an explanation of what is prompting time-sensitivity.

5.6.3 Summary of Q&A

Commissioner Rechtschaffen asked David Sawaya to clarify whether there is anything that currently precludes PG&E from considering external benefits, since Mr. Sawaya mentioned in his presentation that the Commission should consider GHG reductions in determining cost-effectiveness. Mr. Sawaya responded that although he cannot conclusively confirm if there are preclusions, PG&E is currently undertaking work that is prescribed within their GRC and budgets and does not consider GHG reduction as a benefit in its calculation. Commissioner Rechtschaffen then asked, "Is the trigger for analysis and the discussion of these upgrades driven by safety concerns?" Mr. Sawaya answered that upgrades are being driven by risk reduction, safety, or reliability requirements. Michael Colvin added that there is a difference between a reliability upgrade and an emergency safety risk. In the latter scenario, the utility would have to respond in a matter of days. As a result, it would not be feasible to electrify a system to remedy an emergent safety risk.

A question in the chat asked, "To what extent do state building codes need to be modified to expedite electrification?" Mr. Sawaya explained that there has been progress on building codes at both the local and state level to encourage electrification in new buildings. The bigger issue would be electrification retrofits in older buildings. Unless there is a means of requiring replacement of appliances, relying on modifying codes would be a challenging way to accelerate electrification broadly.

Another questioner in the chat noted that Mr. Colvin had suggested not decommissioning equipment that has been recently serviced due to stranded cost risk and asked whether that means that sunk costs should affect decision-making going forward. Mr. Colvin stated that there may be a cost shift in early adoption of electrification to a lower-middle class income customer base who are typically renters and not owners. To minimize the cost shift, you would need to minimize the amount of sunk costs left on the system. Looking into the embedded book value of the system is one way to mitigate this. Mr. Sawaya added that although he agrees with the need to mitigate impacts on remaining customers, he has a diverging opinion on the use of the embedded book value. In his view, the embedded book value should be considered. However, it would not be the primary factor. Consistent with FERC accounting guidelines, PG&E depreciates assets as a group based on the average service life of elements of the system.

A question from the chat asked, "How would IOUs determine the book value of assets on a zonal basis? Would this be done based on number of miles, in other words, imputed versus actual book value?" Mr. Sawaya stated that determining the book value of a single asset is not something they would necessarily do because of their accounting practices.

Another question directed to Mr. Sawaya asked if he could expand on the capital versus expense issue for electrification projects. Mr. Sawaya explained that when the gas utility receives approval for its GRC budget, capital budgets and expense budgets are separate. Currently, using FERC accounting guidelines, behind-the-meter electrification assets would be treated as an expense, which affects customer rates dollar for dollar whereas capital dollars are extended over a long period of time. He added that the Commission should allow PG&E to treat behind-the-meter electrification costs as capital to reduce rate impact.

A question in the chat asked, "Does the book cost of a decommissioned gas line matter? Whether the line has a high cost or a low cost, the utility's total book balance is the same. Doesn't the upward cost pressure result from the reduction in sales with the fuel switching and not from the book cost of the decommissioned pipes?" In response, Mr. Colvin asked how much remaining costs would be spread out to the other customers. Looking at the amount of costs would determine whether it's appropriate to do the electrification at that time.

5.7 Summary of Final Q&A

At the end of the day, there was a final question-and-answer period in which participants could ask questions on any of the day's topics. Marcel Hawiger from TURN began by questioning whether Mr. Sawaya had correctly characterized the way utility revenues are authorized by the Commission. He stated that the Commission authorizes a revenue requirement, which includes both capital and expense. There is no bar to the utility deciding to spend the revenue requirement on capital or expense—that is entirely within the utility's discretion. Mr. Sawaya responded that capital and expense budgets are not fungible between one another. There were no other questions.

6 APPENDIX A

R.20-01-007 Track 2 Workshop 1: Gas Infrastructure

January 10, 2022 | 9:30 a.m. – 4:00 p.m. | Remote participation only
Remote Participation Link:
https://cpuc.webex.com/cpuc/j.php?MTID=m253d3320c16536ce0c96d97512e1d2f0
Toll Call-in: 1-415-655-0002
Meeting Access Code: 2480 535 4677 Event Password: GasPlanning2022

Workshop Purpose: This workshop covers Scoping Memo questions 2.1(a)-2.1(d) of the Assigned Commissioner's Amended Scoping Memo and Ruling, issued on January 5, 2022.[1] This workshop seeks to provide stakeholders with a common understanding of the issues, gather information, and seek feedback. Additionally, workshop participants may begin to develop possible future scenarios and suggest potential solutions.

Intended Outcome: Participants and attendees will have a better understanding of the facts upon which testimony, hearings (if needed), and briefs (if needed) will proceed. Energy Division staff will publish a workshop report in February summarizing the presentations and various discussions.

WORKSHOP AGENDA

9:30 – 9:50	**Welcome** Commissioner Remarks Energy Division Staff Workshop Logistics
9:50 – 10:30	**Scoping Memo Question a:** Should the Commission consider adopting a General Order (GO) analogous to GO 131-D for electric infrastructure projects, that would require site-specific approvals for gas infrastructure projects that exceed a certain size or cost? **Mary Jo Borak and Jack Mulligan**, CPUC Energy and Legal Division Staff **Jennifer Everett,** PG&E **Albert Garcia**, SoCalGas **Matt Vespa,** Earthjustice
10:30 – 10:40	**Q&A**

[1] The scope of Track 2 can be found in the Assigned Commissioner's Amended Scoping Memo and Ruling here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M436/K692/436692151.PDF

10:40 – 11:40 **Scoping Memo Question b:** What criteria should the Commission use to determine whether aging transmission infrastructure should be repaired or replaced when a gas utility requests ratepayer funds?

i. Should the repair or replacement criteria be based on whether that piece of infrastructure is necessary to meet the utility's design standard as determined in Track 1?
ii. What other criteria might be considered?
iii. How should the cost to repair or replace the infrastructure be balanced against its reliability benefits?

Bryon Winget, PG&E
Michael Colvin, Environmental Defense Fund
Catherine Yap, Southern California Generation Coalition
Mark Pocta, Cal Advocates

11:40 – 12:00 **Panel Discussion and Q&A**

12:00 – 1:00 **Lunch Break**

1:00 – 1:45 **Scoping Memo Question c:** What criteria should be used to determine when declining demand can enable transmission lines to be de-rated or decommissioned without harming reliability?

i. How should the Commission define a transmission pipeline vs. a distribution line?
ii. What should the regulatory process be for de-rating a transmission pipeline to a distribution pipeline?

Matt Epuna, CPUC Safety and Enforcement Division
Thomas Finch, Pipeline and Hazardous Materials Safety Administration
Jonathan Peress, SoCalGas

1:45 –2:05 **Panel Discussion and Q&A**

2:05 – 2:10 **Stretch Break**

2:10 – 3:10 **Scoping Memo Question d**: What criteria should the Commission use to determine whether aging distribution infrastructure should be repaired or replaced when a gas utility requests ratepayer funds?

i. What pipeline-related characteristics should be considered when determining whether to replace distribution infrastructure (e.g., downstream impacts, pipeline's role in serving industrial (hard to electrify) load, type of customers served, customer density, age, safety condition, pipe material such as Aldyl-A, proximity to a source of renewable gas?)
ii. What community characteristics such as designation as a disadvantaged community (DAC), should be considered?
iii. What other criteria, if any, should be considered?

iv. What goals should be considered when using these characteristics (e.g., cost savings, pipeline safety, net greenhouse gas reductions, environmental justice)?
v. What non-pipeline alternatives should be considered?
vi. How should the cost of non-pipeline alternatives be compared to the cost of gas pipeline replacement or repair? for example, are there avoided operations and maintenance (O&M) and infrastructure replacement costs for retiring distribution pipelines that could be estimated and incorporated into cost-effectiveness analysis?
vii. If the Commission determines that a distribution pipeline should be decommissioned, what consideration should be given to customers who do not wish to stop their gas service?

Samuel Grandlienard, Southwest Gas
Abigail Solis, Self Help Enterprises
Sam Wade, Coalition for Renewable Natural Gas
Marcel Hawiger, TURN
Claire Halbrook, Gridworks

3:10 – 3:30 **Panel Discussion and Q&A**

3:30 – 3:55 **Final Comments and Q&A (Open to All)**

3:55 – 4:00 **Closing Remarks**
Energy Division Staff

Note: It is expected that one or more CPUC Commissioners may attend and participate in the workshop. One or more advisors to the CPUC Commissioners, as well as other decision-makers, may also be in attendance. The agenda will be publicly noticed on the CPUC's Daily Calendar 10 days in advance, so statements made at the workshop will not constitute a reportable *ex parte* contact. The workshop will be recorded. This agenda is subject to change.

7 APPENDIX B

R.20-01-007 Track 2 Workshop 2: Gas Infrastructure

January 24, 2022 | 9:30 a.m. – 4:30 p.m. | Remote participation only
Remote Participation Link:
https://cpuc.webex.com/cpuc/j.php?MTID=m223a8225abc6ef270805d1f4c977aeef
Toll Call-in: 1-415-655-0002
Meeting Access Code: 2497 283 3080 Event Password: GasPlanning2022

Workshop Purpose: This workshop covers Scoping Memo questions 2.1(e)-2.1(k) of the Assigned Commissioner's Amended Scoping Memo and Ruling, issued on January 5, 2022.[1] This workshop seeks to provide stakeholders with a common understanding of the issues, gather information, and seek feedback. Additionally, workshop participants may begin to develop possible future scenarios and suggest potential solutions.

Intended Outcome: Participants and attendees will have a better understanding of the facts upon which testimony, hearings (if needed), and briefs (if needed) will proceed. Energy Division staff will publish a workshop report in February summarizing the presentations and various discussions.

WORKSHOP AGENDA

9:30 – 9:50 **Welcome**
Commissioner Remarks
Energy Division Staff Workshop Logistics

9:50 – 10:30 **Scoping Memo Question e:** What criteria should be used to determine which distribution lines should have the highest priority for proactive decommissioning?

i. What pipeline-related characteristics should be considered when prioritizing distribution lines for decommissioning (e.g., age, safety condition, pipeline's role in serving industrial (hard to electrify) load, extent to which it has been depreciated, location, customer density, pipe material such as Aldyl-A, proximity to a source of renewable gas)?
ii. What community characteristics, such as designation as a DAC, should be considered?
iii. What other criteria, if any, should be considered?
iv. What goals should be considered when using these characteristics (e.g., cost savings, minimizing stranded assets, pipeline safety, net greenhouse gas reductions, environmental justice)?
v. What non-pipeline alternatives should be considered?

[1] The scope of Track 2 can be found in the Assigned Commissioner's Amended Scoping Memo and Ruling here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M436/K692/436692151.PDF

vi. How should the direct and indirect costs of non-pipeline alternatives be compared to the cost of replacement? For example, are there avoided O&M and pipeline replacement costs for retiring distribution pipelines that could be estimated and incorporated into cost-effectiveness analysis?

vii. If the Commission determines that a distribution pipeline should be decommissioned, what consideration should be given to customers who do not wish to stop their gas service?

viii. What planning and procedures are necessary to ensure that there is sufficient local electric capacity available to reliably serve customers that move off the gas system?

ix. Are there health and safety issues that need to be addressed from decommissioned distribution lines?

x. What procedural mechanism should be used to proactively decommission distribution lines?

Jessica Allison, CPUC Energy Division
Qing Tian, California Energy Commission
Mike Kerans, Pacific Gas and Electric Company
Jina Kim, California Environmental Justice Alliance

10:30 – 10:50 **Q&A**

10:50 – 11:30 **Scoping Memo Question f:** What infrastructure is needed to fulfill the needs of customers who are likely to remain on the gas system the longest, such as electric generators or difficult-to-electrify industrial users?
Scoping Memo Question j: how should the Commission consider the need for gas infrastructure that may be needed to serve new industrial gas customers in difficult to electrify sectors as part of the long-term gas system planning process?

Jan Smutny-Jones, Independent Energy Producers
Shayne Seever, Vista Metals
Dr. Jack Brouwer and Dr. Jeff Reed, University of California, Irvine
Chris DiGiovanni, Pacific Gas and Electric Company

11:30 – 11:50 **Q&A**

11:50 – 12:45 **Lunch Break**

12:45 – 1:25 **Scoping Memo Question g:** What should be the role of existing natural gas storage facilities as a component of the gas utilities' infrastructure portfolio?

Jason Dubchak and Toby McKenna, Rockpoint Gas Storage
Marci Palmstrom, Southern California Edison
Dr. Jane Long, California Center for Science and Technology
Mark Pocta, Cal Advocates

1:25 – 1:45 **Q&A**

1:45 – 1:55	**Stretch Break**
1:55 – 2:40	**Scoping Memo Question h:** How should the monopoly local distribution companies' "obligation to serve all customers who want service" (see D.15-10-050, at 18) be defined, given the state's decarbonization goals? What statutory and policy changes, if any, are needed to effectuate such a definition? **Moderated by Jonathan Bromson,** CPUC Legal Division **Michael Wara**, Stanford Law School **Deborah Behles**, California Environmental Justice Alliance **Justin Gundlach**, New York University School of Law **Ted Lamm and Ethan Elkind,** University of California, Berkeley School of Law
2:40 – 3:05	**Q&A**
3:05 – 3:25	**Scoping Memo Question i**: should the Commission require the achievement of certain milestones (e.g., replacement energy resources are built and operational) before a significant natural gas asset is derated or decommissioned to ensure energy reliability, equity, workforce planning, and other policy goals are maintained and/or achieved throughout this transition? **Delphine Hou**, California Independent System Operator **Marci Palmstrom**, Southern California Edison
3:25 – 3:35	**Q&A**
3:35 – 3:55	**Scoping Memo Question k:** Should the Commission establish a mechanism for streamlined approval of cost-effective, time-sensitive zonal electrification? If so, what should this mechanism be? **David Sawaya**, Pacific Gas and Electric Company **Michael Colvin**, Environmental Defense Fund
3:55 – 4:05	**Q&A**
4:05 – 4:25	**Final Comments and Q&A (Open to All)**
4:25 – 4:30	**Closing Remarks** Energy Division Staff

Note: It is expected that one or more CPUC Commissioners may attend and participate in the workshop. One or more advisors to the CPUC Commissioners, as well as other decision-makers, may also be in attendance. The agenda will be publicly noticed on the CPUC's Daily Calendar 10 days in advance, so statements made at the workshop will not constitute a reportable *ex parte* contact. The workshop will be recorded. This agenda is subject to change.

(END OF ATTACHMENT)